OFFERING MEMORANDUM **CONFIDENTIAL**

Karoon USA Finance Inc

US$350,000,000

10.500% Second-Priority Senior Secured Notes due 2029

fully and unconditionally guaranteed by

Karoon Energy Limited

(incorporated with limited liability in Australia, ACN 107 001 338)

and certain of its subsidiaries

Karoon USA Finance Inc. (the "Issuer"), a wholly-owned subsidiary of Karoon Energy Limited ("Parent Guarantor", and, together with its subsidiaries, "Karoon Energy," "Karoon", "we", "our" and "us"), is offering US$350,000,000 aggregate principal amount of 10.500% Second-Priority Senior Secured Notes due May 14, 2029 (the "Notes"). The Notes will be guaranteed on a senior basis by Karoon Energy Limited (the "Parent Guarantor") and certain of its subsidiaries. The Notes will bear interest at an annual rate of 10.500%. The first interest payment on the Notes will be made on November 14, 2024. Thereafter, interest on the Notes will be payable semi-annually in arrears on May 14 and November 14 of each year.

The Notes will be fully and unconditionally guaranteed (the "Guarantees") by the Parent Guarantor and each of its subsidiaries that is a guarantor or obligor under our RBL facility (as defined herein) and any future, direct or indirect, wholly-owned restricted subsidiary that (i) incurs or guarantees indebtedness under the RBL facility or incurs or guarantees other credit facilities or indebtedness of the Parent Guarantor, Issuer or any other Guarantor in excess of US$25 million (the "Subsidiary Guarantors" and together with the Parent Guarantor, the "Guarantors"). The Notes will be secured by second-priority security interests over substantially all of the Parent Guarantor's and its subsidiaries' assets, subject to certain customary exceptions (the "Collateral"). The Collateral also secures our obligations under the RBL facility and associated hedging, and will secure other indebtedness that is permitted to rank on a senior-priority basis ahead of the Notes and Guarantees, on a first- or senior-priority basis. The Notes and Guarantees will (i) rank equally in right of payment with all of the Issuer's and Guarantors' existing and future senior obligations, (ii) rank senior in right of payment to any of the Issuer's and Guarantors' obligations that are subordinated to the Notes and Guarantees, (iii) be effectively senior in right of payment to all existing and future obligations of the Issuer and Guarantors that are unsecured or secured by the Collateral on a junior basis to the Notes and Guarantees, in each case, to the extent of the value of the Collateral that is available to satisfy the obligations under the Notes and Guarantees, (iv) be effectively *pari passu* with any of the Issuer's and Guarantors' existing and future obligations that are secured by the Collateral on a second-priority basis, (v) be effectively junior to any of the Issuer's and Guarantors' existing and future obligations that are secured by the Collateral on a first- or senior-priority basis to the Notes and Guarantees, including indebtedness under the RBL facility and associated hedging, to the extent of the value of the Collateral and (vi) be structurally subordinated to any indebtedness and other liabilities of any subsidiary of the Issuer or the Guarantors that is not a guarantor of the Notes.

We may redeem any of the Notes beginning on May 14, 2026 at the redemption prices set forth in this offering memorandum, together with accrued and unpaid interest, if any, to but excluding the redemption date. We may also redeem any of the Notes at any time prior to May 14, 2026 at a price equal to 100% of the aggregate principal amount of the Notes redeemed plus a make-whole premium and accrued and unpaid interest, if any, to but excluding the redemption date. In addition, prior to May 14, 2026 we may redeem up to 40% of the aggregate principal amount of the Notes with an amount equal to the net cash proceeds of certain equity offerings, at a redemption price equal to 110.500% of the aggregate principal amount of the Notes plus accrued and unpaid interest, if any, to but excluding the redemption date. Prior to May 14, 2026, we may redeem during each 12-month period commencing on the Issue Date (as defined herein) up to 10% of the original principal amount of the Notes at a redemption price equal to 103% of the principal amount of the Notes redeemed, plus accrued and unpaid interest, if any, to but excluding the redemption date. If certain developments affecting taxation occur, we may redeem all, but not less than all, of the Notes at a redemption price equal to 100% of the principal amount of the Notes redeemed, plus accrued interest.

We intend to apply for the listing and quotation of the Notes on the Singapore Exchange Securities Trading Limited (the "SGX-ST"). The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions or reports contained in this offering memorandum. Admission of the Notes to the Official List of the SGX-ST, and the listing and quotation of the Notes on the Official List of the SGX-ST, are not to be taken as an indication of the merits of the Issuer, the Guarantors, our subsidiaries, our associated companies, the Notes or the Guarantees. The Notes will be traded on the SGX-ST in a minimum board lot size of S$200,000 (or its equivalent in foreign currencies) so long as any of the Notes are listed on the SGX-ST and the rules of the SGX-ST so require. There is currently no public market for the Notes.

Investing in the Notes involves risks. See "Risk factors" beginning on page 38.

Price for Notes: 100.000% plus accrued interest, if any, from May 14, 2024.

The Notes and the Guarantees have not been, and will not be, registered under the Securities Act of 1933 (the "Securities Act") or any securities laws of any state of other jurisdiction of the United States. Accordingly, the Notes and the Guarantees are being offered and sold only to persons reasonably believed to be qualified institutional buyers in the United States in accordance with Rule 144A under the Securities Act ("Rule 144A") and outside the United States to persons that are not U.S. persons and are not acting for the account or benefit of a U.S. person in offshore transactions in reliance on Regulation S under the Securities Act ("Regulation S"). Prospective investors that are qualified institutional buyers are hereby notified that the seller of the Notes and the Guarantees may be relying on the exemption from the provisions of Section 5 of the Securities Act provided by Rule 144A. For a description of certain restrictions on transfers of the Notes and the Guarantees, see "Transfer restrictions."

The Issuer expects the Notes to be ready for delivery in book-entry form through the facilities of The Depository Trust Company ("DTC") and its participants, including Clearstream Banking S.A. ("Clearstream") and Euroclear Bank SA/NV ("Euroclear"), on or about May 14, 2024.

Sole Global Coordinator and Joint Physical Bookrunner	*Joint Physical Bookrunner*
Deutsche Bank Securities	**ING**

May 7, 2024

You should rely only on the information contained in this offering memorandum and in any pricing term sheet provided to you by the initial purchasers, as defined under "Plan of distribution." We have not, and the initial purchasers have not, authorized anyone to provide you with different information. We are not, and the initial purchasers are not, making an offer of the Notes and Guarantees in any jurisdiction where the offer is not permitted. You should not assume that the information contained in this offering memorandum is accurate as of any date other than the date on the cover of this offering memorandum.

TABLE OF CONTENTS

NOTICE TO INVESTORS

In this offering memorandum, unless the context otherwise requires, references to:

- "Karoon Energy," "Karoon Energy Limited," "Karoon," "we," "our" and "us" are references to Karoon Energy Limited (ACN 107 001 338) or to Karoon Energy Limited and its subsidiaries (including joint venture non-operated operations), as the context requires;
- "Group" is a reference to the Parent Guarantor and its subsidiaries;
- the "Issuer" is a reference to Karoon USA Finance Inc;
- the "Parent Guarantor" is a reference to Karoon Energy Limited (ACN 107 001 338); and
- the "Subsidiary Guarantors" are references to Karoon Energy International Pty Ltd (ABN 91 124 815 925), KEI (Brazil Santos) Pty Ltd (ABN 13 128 939 328), KEI Finance 1 Pty Ltd (ABN 92 670 320 091), ACN 672 679 793 Pty. Ltd. (ACN 672 679 793), Karoon Petroleo & Gas Ltda (CNPJ: 09.347.916/0001-97) and KUSA Inc. and "Guarantors" are references to the Parent Guarantor and the Subsidiary Guarantors.

This offering memorandum has been prepared by us solely for use in connection with the proposed offering of the Notes and Guarantees described in this offering memorandum. This offering memorandum is personal to each offeree and does not constitute an offer to any other person or to the public generally to subscribe for or otherwise acquire securities. Distribution of this offering memorandum to any person other than the prospective investor and any person retained to advise such prospective investor with respect to its purchase is unauthorized, and any disclosure of any of its contents, without our prior written consent, is prohibited. Each prospective investor, by accepting delivery of this offering memorandum, agrees to the foregoing and to make no copies of this offering memorandum or any documents referred to in this offering memorandum.

For definitions of certain terms used in this offering memorandum, see "Glossary."

None of the initial purchasers, the Trustee (as defined below) or the Agents (as defined below) make any representation or warranty, express or implied, as to the accuracy or completeness of the information contained in this offering memorandum. Nothing contained in this offering memorandum is, or shall be relied upon as, a promise or representation by the initial purchasers, the Trustee or the Agents as to the past or future. We have furnished the information contained in this offering memorandum. None of the initial purchasers, the Trustee or the Agents assume any responsibility for the accuracy or completeness of any such information.

The Notes are subject to restrictions on transferability and resale and may not be transferred or resold except as permitted under the Securities Act and the applicable state securities laws pursuant to registration or exemption therefrom. As a prospective investor, you should be aware that you may be required to bear the financial risks of this investment for an indefinite period of time. Please refer to "Plan of distribution" and "Transfer restrictions."

In making an investment decision, prospective investors must rely on their own examination of the Issuer and the Guarantors and the terms of the offering, including the merits and risks involved. Prospective investors should not construe anything in this offering memorandum as investment, legal, business or tax advice. Each prospective investor should consult its own advisors as needed to make its investment decision and to determine whether it is legally permitted to purchase the Notes under applicable legal investment or similar laws or regulations.

This offering memorandum contains summaries believed to be accurate with respect to certain documents, but reference is made to the actual documents for complete information. All such summaries are qualified in their entirety by such reference. Copies of documents referred to herein will be made available to prospective investors upon request to us or the initial purchasers.

This offering memorandum is not, and is not intended to be a "disclosure document" for the purposes of Chapter 6D of the Australian Corporations Act 2001 (Cth) (the "Australian Corporations Act") or a "Product Disclosure Statement" for the purposes of Chapter 7 of the Australian Corporations Act. No action has been taken by us that would permit a public offering of the Notes in Australia. In particular, this offering memorandum has not been lodged or registered with the Australian Securities and Investments Commission ("ASIC").

Notes may not be offered for sale nor may applications for the sale or purchase of any Notes be invited in Australia (including an offer or invitation that is received by a person in Australia) and neither this offering memorandum, any supplement hereto, any information memorandum, advertisement nor any other offering material relating to the Notes or Guarantees may be distributed or published in Australia unless (i) the aggregate consideration payable by each offeree or invitee is at least A$500,000 (or its equivalent in other currencies, disregarding moneys lent by the offeror or its associates) or the offer or invitation otherwise does not require disclosure to investors in accordance with Part 6D.2 or Part 7.9 of the Australian Corporations Act, (ii) the offer or invitation is not made to a person who is a "retail client" within the meaning of section 761G of the Australian Corporations Act, (iii) such action complies with all applicable laws, regulations and directives, and (iv) such action does not require any document to be lodged with ASIC.

The communication of this offering memorandum and any other document or materials relating to the issue of the Notes is not being made, and such documents and/or materials have not been approved, by an authorized person for the purposes of section 21 of the United Kingdom's Financial Services and Markets Act 2000, as amended (the "FSMA"). Accordingly, such documents and/or materials are not being distributed to, and must not be passed on to, the general public in the United Kingdom.

This offering memorandum and any such other documents and/or materials are for distribution only to persons in the United Kingdom who (i) have professional experience in matters relating to investments and who fall within the definition of investment professionals (as defined in Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the "Financial Promotion Order")), (ii) fall within Article 49(2)(a) to (d) of the Financial Promotion Order, or (iii) are other persons to whom it may otherwise lawfully be made under the Financial Promotion Order (all such persons together being referred to as "relevant persons"). This offering memorandum is directed only at relevant persons and must not be acted on or relied on by persons who are not relevant persons. Any investment or investment activity to which this offering memorandum and any other document or materials relates will be engaged in only with relevant persons. Any person in the United Kingdom that is not a relevant person should not act or rely on this offering memorandum or any of its contents.

THE NOTES ARE BEING OFFERED AND SOLD WITHIN THE UNITED STATES TO PERSONS REASONABLY BELIEVED TO BE QUALIFIED INSTITUTIONAL BUYERS IN RELIANCE ON RULE 144A AND OUTSIDE THE UNITED STATES TO PERSONS THAT ARE NOT U.S. PERSONS AND ARE NOT ACTING FOR THE ACCOUNT OR BENEFIT OF A U.S. PERSON IN OFFSHORE TRANSACTIONS IN RELIANCE ON REGULATION S OR ANOTHER EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT. PROSPECTIVE PURCHASERS ARE HEREBY NOTIFIED THAT SELLERS OF NOTES MAY BE RELYING ON THE EXEMPTION FROM THE PROVISIONS OF SECTION 5 OF THE SECURITIES ACT PROVIDED BY RULE 144A. THE NOTES ARE SUBJECT TO ADDITIONAL SELLING RESTRICTIONS. FOR A DESCRIPTION OF THESE AND CERTAIN FURTHER RESTRICTIONS ON OFFERS, SALES AND TRANSFERS OF NOTES AND THE DISTRIBUTION OF THIS OFFERING MEMORANDUM, SEE "PLAN OF DISTRIBUTION" AND "TRANSFER RESTRICTIONS."

THE NOTES HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE SECURITIES AND EXCHANGE COMMISSION ("SEC"), ANY STATE SECURITIES COMMISSION IN THE UNITED STATES OR ANY OTHER U.S. REGULATORY AUTHORITY, NOR HAS ANY OF THE FOREGOING AUTHORITIES PASSED UPON OR ENDORSED THE MERITS OF THE OFFERING OF THE NOTES OR THE ACCURACY OR ADEQUACY OF THIS OFFERING MEMORANDUM.

PROHIBITION OF SALES TO EUROPEAN ECONOMIC AREA ("EEA") RETAIL INVESTORS – This offering memorandum is not a prospectus for the purposes of Regulation (EU) 2017/1129 (the "Prospectus Regulation") as it forms part of domestic law in the United Kingdom by virtue of the European Union (Withdrawal) Act 2018, as amended by the European Union (Withdrawal Agreement) Act 2020 (the "EUWA") (the "UK Prospectus Regulation"). The Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the EEA. For these purposes, a retail investor means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of Directive 2014/65/EU (as amended, "MiFID II"); or (ii) a customer within the meaning of Directive (EU) 2016/97 (the "Insurance Distribution Directive"), where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; or (iii) not a qualified investor as defined in the Prospectus Regulation. Consequently, no key information document required by Regulation (EU) No 1286/2014 (as amended, the "PRIIPs Regulation") for offering or selling the Notes or otherwise making them available to retail investors in the EEA has been prepared and therefore offering or selling the Notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation.

PROHIBITION OF SALES TO UK RETAIL INVESTORS – This offering memorandum is not a prospectus for the purposes of UK Prospectus Regulation. The Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the United Kingdom. For these purposes, a retail investor means a person who is one (or more) of: (i) a retail client, as defined in point (8) of Article 2 of Regulation (EU) No 2017/565 as it forms part of domestic law in the United Kingdom by virtue of the EUWA; or (ii) a customer within the meaning of the provisions of the FSMA and any rules or regulations made under the FSMA to implement the Insurance Distribution Directive, where that customer would not qualify as a professional client as defined in point (8) of Article 2(1) of Regulation (EU) No 600/2014 as it forms part of domestic law in the United Kingdom by virtue of the EUWA; or (iii) not a qualified investor as defined in Article 2 of the UK Prospectus Regulation. Consequently, no key information document required by Regulation (EU) No 1286/2014 as it forms part of domestic law in the United Kingdom by virtue of the EUWA (the "UK PRIIPs Regulation") for offering or selling the Notes or otherwise making them available to retail investors in the United Kingdom has been prepared and therefore offering or selling the Notes or otherwise making them available to any retail investor in the United Kingdom may be unlawful under the UK PRIIPs Regulation.

UK MiFIR (AS DEFINED BELOW) PRODUCT GOVERNANCE/PROFESSIONAL INVESTORS AND ELIGIBLE COUNTERPARTIES ONLY TARGET MARKET – Solely for the purposes of the product approval process of any relevant initial purchaser that considers itself as a manufacturer pursuant to the FCA Handbook Product Intervention and Product Governance Sourcebook (the "UK MiFIR Product Governance Rules") (each a "UK Manufacturer" and, together, the "UK Manufacturers"), the target market assessment in respect of the Notes has led to the conclusion that: (i) the target market for the Notes is only eligible counterparties, as defined in the FCA Handbook Conduct of Business Sourcebook, and professional clients as defined in Regulation (EU) No. 600/2014 as it forms part of domestic law in the United Kingdom by virtue of the EUWA ("UK MiFIR"); and (ii) all channels for distribution of the Notes to eligible counterparties and professional clients are appropriate. Any person subsequently offering, selling or recommending the Notes (a "UK distributor") should take into consideration the manufacturer's target market assessment; however, a UK distributor subject to the FCA Handbook Product Intervention and Product Governance Sourcebook is responsible for undertaking its own target market assessment in respect of the Notes (by either adopting or refining the manufacturer's target market assessment) and determining appropriate distribution channels.

NOTICE TO INVESTORS IN BRAZIL – The Notes (and the related Guarantees) have not been, and will not be, registered with the Brazilian Securities and Exchange Commission (Comissão de Valores Mobiliários), and may not be placed, distributed, offered or sold in the Brazilian capital market, except in circumstances that do not constitute a public offering, placement or unauthorized distribution of securities in the Brazilian capital market, under Brazilian laws and regulations. Documents relating to the offering of the Notes, as well as information contained therein, may not be supplied to the public in Brazil, nor be used in connection with any offer for subscription or sale of the Notes to the public in Brazil. Persons wishing to offer or acquire the Notes within Brazil should consult with their own counsel as to the applicability of registration requirements or any exemption therefrom.

FORWARD-LOOKING STATEMENTS

This offering memorandum includes forward-looking statements within the meaning of United States securities laws. Forward-looking statements involve known and unknown risks, uncertainties and other factors that are in some cases beyond our control. These forward-looking statements include, but are not limited to, all statements other than statements of historical facts contained in this offering memorandum, including, without limitation, those regarding our future financial position and results of operations, our strategy, plans, objectives, goals and targets and future developments or trends in the markets where we participate or are seeking to participate. Some of these statements can be identified by terms and phrases such as "anticipate," "should," "likely," "foresee," "believe," "estimate," "expect," "intend," "continue," "could," "may," "plan," "project," "predict," "will," and similar expressions and include references to assumptions that we believe are reasonable as of the date of this offering memorandum and relate to our future prospects, developments and business strategies.

Many factors could cause our actual results, performance or achievements to be materially different from any future results, performance or achievements that may be expressed or implied by such forward-looking statements. Factors that could cause our actual results to differ materially from those expressed or implied in such forward-looking statements, include, but are not limited to:

- declines in oil and gas prices;
- lower than expected production or additional costs and liabilities due to a range of production risks;
- our dependence on facilities and infrastructure owned and/or operated by third parties, including our dependence of our Brazilian production on a single floating production, storage and offloading facility owned by Altera & Ocyan;
- risks associated with our joint venture and farm-in arrangements;
- inherent technical and geological uncertainty of our oil and gas reserve and resource estimates;
- risks related to completed or potential acquisitions;
- inflationary pressures;
- uncertainty and negative impacts on the economy and energy and capital markets caused by the Russian invasion of Ukraine, tensions in the Taiwan Strait and in the Middle East or any other geopolitical events;
- political risks in Brazil and the United States;
- our ability to replace our existing reserves;
- the highly competitive nature of the oil and gas industry;
- new technologies posing risks of obsolescence to our current exploration and drilling methods;
- concentration on two assets of our production, revenue and cash flow from operating activities;
- increasing attention to environmental, social and governance ("ESG") matters and risks related to ESG aspirations, targets and disclosures;

- our concentrated oil and gas customer base;
- effects of alternative sources of energy on the demand for fossil fuels;
- substantial costs if we fail to ensure the safety of our employees and contractors;
- operational risk and intensive capital expenditure requirements of offshore oil operations;
- the adequacy of our insurance arrangements to cover losses arising from our operations;
- loss of key personnel or a shortage of skilled and semi-skilled labor;
- cyber-security risks and other similar threats;
- outbreak of contagious diseases;
- extensive laws and regulations of the oil and gas industry, including drilling laws;
- our dependence on exploration and production licenses;
- costs of compliance with environmental laws and future removal and environmental restoration costs;
- laws regulating greenhouse gas emissions;
- anti-corruption, anti-bribery, anti-money laundering, sanctions and similar laws;
- tax liabilities;
- litigation, arbitration and regulatory action;
- other risks associated with our financial arrangements and the Notes; and
- other factors referred to in "Risk factors" and elsewhere in this offering memorandum.

We caution that the foregoing list of important factors is not exhaustive. Forward-looking statements are based upon management's good faith assumptions relating to the financial, market, regulatory and other relevant environments that will exist and affect our business and operations in the future. We cannot give investors any assurance that the assumptions upon which management based its forward-looking statements will prove to be correct, or that our business and operations will not be affected in any substantial manner by other factors not currently foreseeable by management or beyond our control.

Accordingly, investors are strongly cautioned not to place undue reliance on any forward-looking statement, particularly in light of the significant volatility, uncertainty and disruption caused by the war between Ukraine and Russia, the ongoing regional conflict in the Middle East, and ongoing tensions between China and the United States and its allies, and each of their associated impacts on global fuel prices, global supply chains and economic growth. These forward-looking statements speak only as of the date of this offering memorandum. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement included in this offering memorandum should not be construed as exhaustive. You should also read, among other things, the risks and uncertainties described in "Risk factors" and in the documents that we refer to in "Available information." All forward-looking statements are qualified by these cautionary statements.

CREDIT RATINGS

There are references in this offering memorandum to credit ratings. Credit ratings are for distribution only to a person (a) who is not a "retail client" within the meaning of section 761G of the Corporations Act and is also a sophisticated investor, professional investor or other investor in respect of whom disclosure is not required under Part 6D.2 or 7.9 of the Corporations Act, and (b) who is otherwise permitted to receive credit ratings in accordance with applicable law in any jurisdiction in which the person may be located. Anyone who is not such a person is not entitled to receive this offering memorandum and any person who receives this offering memorandum is advised that they must not distribute it to any person who is not entitled to receive it.

A credit rating is not a recommendation to buy, sell or hold securities. There is no assurance that any rating will remain in effect for a given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances warrant such revision or withdrawal. Ratings may be changed, withdrawn or suspended at any time. The rating of each credit rating agency should be evaluated independently of any other rating. We are under no obligation to update information regarding such ratings should they change over time.

AVAILABLE INFORMATION

Neither the Issuer nor any of the Guarantors are subject to the information and reporting requirements of the Exchange Act. While any Notes remain outstanding, we will during any period in which we are not subject to Section 13 or 15(d) of the Exchange Act, or are exempt from reporting pursuant to Rule 12g3-2(b) under the Exchange Act, make available to any "qualified institutional buyer," or QIB, who holds any Notes and any prospective purchaser of a Note who is a QIB designated by such holder of such Note, upon the request of such holder or prospective purchaser, the information required to be provided to such holder or prospective purchaser by Rule 144A(d)(4) under the Securities Act. We file annual reports and half-year reports with the Australian Securities Exchange ("ASX"). You may obtain copies of the documents filed with the ASX from its website at www.asx.com.au.

In addition, copies of such documents can be obtained from the website of the SGX-ST at www.sgx.com. The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions expressed or reports contained in any such document.

None of the information on a website referred to herein is incorporated by reference herein or otherwise deemed to be a part of this offering memorandum. Any references to websites are for informational purposes only.

ENFORCEMENT OF CIVIL LIABILITIES

The Issuer and the Guarantors are entities organized under the laws of the United States, Australia and Brazil. A majority of the directors and officers of these entities reside outside the United States, principally in Australia. A substantial portion of the assets of these entities, and the assets of the directors, officers and experts, are located outside the United States. Therefore, you may not be able to effect service of process within the United States upon these entities or persons so that you may enforce judgments of United States courts against them in the United States based on the civil liability provisions of the United States federal securities laws.

In addition, there are doubts as to the enforceability in Australia and Brazil in original actions or in actions for enforcement of judgments of United States courts, of civil liabilities based on United States federal securities laws. Also, judgments of United States courts (whether or not such judgments relate to United States federal securities laws) will not be enforceable in Australia and Brazil in certain other circumstances, including, among others, where such judgments contravene local public policy, breach the rules of natural justice or general principles of fairness or are obtained by fraud, are not for a fixed or readily ascertainable sum, are subject to appeal, dismissal, stay of execution or otherwise not final and conclusive, or involve multiple or punitive damages or where the proceedings in such courts are of a revenue or penal nature.

See "Independent auditors" for a description of PricewaterhouseCooper's limitation of liability under a professional limitation on liability scheme in Australia.

AUSTRALIAN EXCHANGE CONTROLS

The Financial Transaction Reports Act 1988 (Cth) (the "Financial Transaction Reports Act"), the Anti-Money Laundering and Counter-Terrorism Financing Act 2006 (Cth) (the "AML/CTF Act"), the Autonomous Sanctions Act 2011 (Cth) (the "Autonomous Sanctions Act"), the Charter of the United Nations Act 1945 (Cth) (the "United Nations Act"), and other Australian regulations, including the regulations made under the United Nations Act and under the Autonomous Sanctions Act, control the import and export of capital and remittance of payments involving non-residents of Australia and restrict the dealing in assets owned or controlled by designated persons or entities (collectively, the "Applicable Regulations"). Unless, as required, the Minister for Foreign Affairs has granted a permit authorizing a transaction that would otherwise contravene a sanctions regulation made under the Autonomous Sanctions Act or the United Nations Act, certain payments, transactions and dealing with assets, that involve or are connected in certain ways with any of the following are, subject to limited exceptions, restricted or prohibited:

- prescribed governments (and their statutory authorities, agencies and entities); and
- prescribed persons, entities and assets.

Prescribed persons, entities and assets (e.g., vessels) are those prescribed under regulations and instruments of the United Nations Act and the Autonomous Sanctions Act. DFAT maintains a list of the persons and entities that are directly subject to sanctions. The list is available to the public at DFAT's website at https://www.dfat.gov.au/international-relations/security/sanctions/Pages/consolidated-list. This list does not include persons that are subject to sanctions under the Applicable Regulations because they are acting at the direction of another person that is subject to sanctions or an entity that is owned or controlled by a person that is subject to sanctions. The list of persons, entities and assets that are subject to these sanctions will change over time. DFAT's website and the information contained on the website is not part of this offering memorandum.

Currently the consolidated list includes, for example:

- certain persons and entities responsible for, or complicit in, the threat to the sovereignty and territorial integrity of Ukraine;
- certain individuals associated with the former Federal Republic of Yugoslavia (in limited circumstances) and known supporters associated with the former Milosevic regime;
- certain individuals and entities who engage in, or have engaged in, activities that seriously undermine democracy, respect for human rights and the rule of law in Zimbabwe;
- certain persons and entities associated with the Democratic People's Republic of Korea (North Korea);
- certain persons and entities associated with the Democratic Republic of the Congo, Somalia, Sudan, South Sudan, Lebanon, the Central African Republic, ISIL (Da'esh), Al-Qaida, Yemen, the Taliban, Mali or the government of Iraq;
- certain persons associated with the military of Myanmar and certain other state-owned or military owned enterprises in Myanmar;
- certain persons associated with the former Gaddafi regime in Libya;
- certain persons and entities associated with the Syrian regime or responsible for human rights abuses in Syria;
- certain persons and entities associated with Iran;
- certain persons and entities associated with Russia; and
- certain persons and entities involved in terrorist activities, including terrorist financing.

However, these are subject to change from time to time.

The Financial Transaction Reports Act and the AML/CTF Act impose reporting obligations on "cash dealers" that are a party to significant transfers of physical currency from one person to another to the Australian Transaction Report and Analysis Centre, known as "AUSTRAC." Under the Financial Transaction Reports Act and the AML/CTF Act, a person who transfers A$10,000 or more (or the foreign currency equivalent) in physical currency into or out of Australia, must, subject to certain exemptions, report details of such transfers to AUSTRAC.

FINANCIAL INFORMATION PRESENTATION

Starting July 1, 2023, we have changed our financial year from ending on June 30 of each year to ending on December 31 of each year. This aligns our financial year with Brazil's and the United States' tax year as well as other Australian global oil and gas industry peers. As a result of this change, we had a transitional financial year beginning on July 1, 2023 and ending on December 31, 2023. Our current financial year commenced on January 1, 2024 and will end on December 31, 2024.

This offering memorandum includes our audited consolidated financial statements as of and for the transitional financial year ended December 31, 2023 ("TY23"), our audited consolidated financial statements as of and for the years ended June 30, 2023 ("FY23") and June 30, 2022 ("FY22") and our unaudited condensed consolidated financial statements as of and for the half-year ended December 31, 2022 ("HY23"). The audited consolidated financial statements as of and for FY22 include financial information for the year ended June 30, 2021 ("FY21") as a comparative.

Our audited consolidated financial statements included in this offering memorandum have been prepared in accordance with Australian Accounting Standards ("AAS") and other authoritative pronouncements of the Australian Accounting Standards Board ("AASB"). They also comply with International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB"). Our unaudited condensed consolidated financial statements included in this offering memorandum have been prepared in accordance with Australian Accounting Standards AASB 134 *Interim Financial Reporting* and comply with IAS 34 *Interim Financial Reporting* as issued by the IASB. The unaudited condensed consolidated financial statements as of and for the half-year ended December 31, 2022 have been reviewed by PricewaterhouseCoopers, independent auditors, in accordance with ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity* and the PricewaterhouseCoopers review report is included in this offering memorandum. The audited consolidated financial statements as of and for the transitional financial year ended December 31, 2023 and the financial years ended June 30, 2023 and 2022 have been audited by PricewaterhouseCoopers, independent auditors, in accordance with Australian Auditing Standards and the PricewaterhouseCoopers audit reports are included in this offering memorandum.

Investors should note that AAS and IFRS differ from generally accepted accounting principles in the United States ("US GAAP"), and those differences may be material to the financial information contained in this offering memorandum. Investors should consult their own professional advisors for an understanding of the differences between AAS, IFRS and US GAAP and how those differences might affect the financial information contained in this offering memorandum. We have not provided a quantitative or narrative discussion of these differences in this offering memorandum. Certain amounts (including percentage amounts) have been rounded for convenience; as a result, certain figures may not sum to total amounts or equal quotients.

This offering memorandum also includes the audited statements of revenues and direct operating expenses of the assets we acquired an interest in in the Mississippi Canyon Blocks in the US Gulf of Mexico from LLOG Exploration Offshore L.L.C. and LLOG Omega Holdings, L.L.C. (together, "LLOG") on December 21, 2023 (the "Who Dat assets") for each of the two years in the period ended December 31, 2023.

The audited statements of revenues and direct operating expenses included in this offering memorandum have been prepared in accordance with US GAAP. As these statements only presented revenues and direct operating expenses, we would not have needed to make any material changes to present these statements in accordance with AAS/IFRS. These statements were audited by Ernst & Young LLP, independent auditors, in accordance with auditing standards generally accepted in the United States of America and the Ernst & Young LLP audit report is included in this offering memorandum. Investors should note that these statements of revenues and direct operating expenses were prepared for the purpose of inclusion in this offering memorandum and are not intended to be a complete presentation of the revenues and expenses of the Who Dat assets.

UNAUDITED PRO FORMA COMBINED FINANCIAL INFORMATION

This offering memorandum includes certain unaudited pro forma combined financial information that has been prepared for the purpose of illustrating the impact the acquisition of the Who Dat assets might have had on our consolidated statement of profit and loss for the year ended December 31, 2023. The unaudited pro forma combined statement of profit or loss for the year ended December 31, 2023 gives effect to the acquisition of the Who Dat assets and related financing transactions as if they had occurred on January 1, 2023.

The assumptions and estimates underlying the unaudited pro forma adjustments applied to the historical financial information of Karoon Energy and of the Who Dat assets to present the unaudited pro forma financial information are described in the notes to the unaudited pro forma combined financial information.

The unaudited pro forma combined financial information should be read together with our historical financial statements and the audited statements of revenues and direct operating expenses of the Who Dat assets, both of which are included elsewhere herein.

The unaudited pro forma combined financial information has been presented for illustrative purposes only and is not intended to represent or be indicative of the results of operations or the financial position of Karoon Energy that would have been recorded had the acquisition of the Who Dat assets been completed as of the dates presented and should not be taken as representative of the future results of operations or financial position of Karoon Energy.

Investors should note that the unaudited pro forma combined financial information included in this offering memorandum does not purport to comply with the requirements of Article 11 of Regulation S-X under the Securities Act or the American Institute of Certified Public Accountants' published guidelines for the preparation and presentation of pro forma financial information. Neither the underlying pro forma adjustments nor the resulting pro forma financial information have been audited or reviewed in accordance with AAS. Accordingly, the unaudited pro forma combined financial information presented in this offering memorandum should not be relied upon by investors to provide the same quality of information as information that has been subject to an audit or review by an independent auditor. **Investors are cautioned not to place undue reliance on the pro forma combined financial information contained in this offering memorandum**.

NON-IFRS FINANCIAL MEASURES

We use a number of operational measures and non-IFRS financial measures to assess the financial and operational performance of our business. These non-IFRS measures do not have standardized meanings prescribed by AAS or IFRS or by other authoritative pronouncements issued by the AASB or IFRS as issued by IASB, and therefore may not be comparable with other similarly titled measures presented by other entities, nor should these be interpreted as an alternative to other financial measures determined in accordance with AAS or IFRS. We believe these operational measures and non-IFRS measures provide useful information about our business and our management considers these measures in analyzing our operating and financial performance.

The non-IFRS measures we use include:

- EBITDA is earnings before interest, tax, depreciation, depletion and amortization (but including the depreciation and interest on our FPSO right of use asset).

- Interest cover ratio is our underlying EBITDA divided by our net interest expense.

- Gearing ratio is our net debt divided by net debt plus equity.

- Leverage ratio is our net debt divided by our underlying EBITDA.

- Net debt/(cash) is our total borrowings (excluding transaction costs) less cash and cash equivalents.

- Net interest expense is our interest expense minus our interest income.

- PV-10 measures are the period-end present values of the estimated future cash inflows from the relevant reserves category less future development and production costs and discounted at 10% to reflect the timing of future cash flows, using pricing assumptions in effect at the end of the period. PV-10 figures presented in this offering memorandum should not be construed as an estimate of the fair market value of the properties. See also "Cautionary note regarding PV-10 values."

- Underlying EBITDA is our EBITDA as adjusted for several non-cash items and other expenses that we believe are not representative of our underlying performance.

These operational and non-IFRS financial measures should not be considered in isolation from, or as a substitute for, financial information prepared in accordance with IFRS. See "Management's discussion and analysis of financial condition and results of operations—Overview—Key operational measures and non-IFRS financial measures" for information about why we consider these metrics useful and a discussion of the material limitations of these measures, as well as a reconciliation of these measures to the most directly comparable financial measure prepared in accordance with IFRS.

EXCHANGE RATES AND CONVERSION FACTORS

Currency of presentation and exchange rates

The consolidated financial statements of Karoon Energy, including the financial information included in this offering memorandum, are presented in United States dollars. In this offering memorandum, references to "A$" are to Australian dollars; references to "R$" are to Brazilian Real, references to "US$" or "U.S. dollars" are to United States dollars, and references to "S$" are to Singapore dollars.

This offering memorandum includes references to Brazilian real amounts, which have been translated into US$ amounts. Unless otherwise stated, we have translated R$ into US$ at our transitional financial year end rate as of December 31, 2023 of R$1 = US$0.2034.

The A$ is convertible into US$ at freely floating exchange rates and there are currently no restrictions on the flow of A$ between Australia and the United States, except as described in "Australian exchange controls" above.

Conversion factors

We have used a conversion factor of 6 mcf equaling 1 boe to convert from gas to oil equivalent.

CAUTIONARY NOTE REGARDING INDUSTRY AND THIRD-PARTY DATA

This offering memorandum contains market data and statistics, third party estimates and other information (including industry forecasts and projections). Market data used throughout this offering memorandum have been obtained from independent experts, independent industry publications and other publicly available information, including information in the report attached hereto as Annex B which was prepared by Wood Mackenzie (see "Independent consultant reports").

The industry and market data contained in this offering memorandum is based on estimates and assumptions that we believe to be reasonable. Although we believe the third-party market data estimates and projections and our own internally generated data, which we used in preparing management estimates, to be reliable, we have not independently verified such information or the underlying assumptions relied upon therein, and we cannot guarantee or assure you as to its accuracy or completeness or as to the accuracy or completeness of any underlying assumptions used in preparing such information.

Investors should note that industry data and statistics are often based on extrapolating from limited data and subject to a range of limitations and possible errors, including errors in data collection and the possibility that relevant data has been omitted. Certain of the data and statistics are based on market research, which itself is based on sampling and subjective judgments by both the researchers and the respondents, including judgments about what types of products and transactions should be included in the relevant market. In addition, the value of comparisons of statistics for different markets is limited by many factors, including that (a) the markets are defined differently, (b) the underlying information was gathered by different methods and (c) different assumptions were applied in compiling the data. As a result, this data is subject to uncertainty and not necessarily reflective of actual market conditions. To the extent the information relates to future events, it is subject to additional risks and uncertainties and may change as a result of various factors as described elsewhere within this offering memorandum. In particular, estimates, forecasts and projections involve risks and uncertainties and are subject to change based on factors discussed in the "Risk factors" section and elsewhere herein.

INDEPENDENT CONSULTANT REPORTS

Information in this offering memorandum includes a summary of a report, dated March 18, 2024, regarding estimates of the reserves, contingent resources and PV-10 future net revenues of Baúna. The report this summary is based on was prepared by our independent expert, AGR Energy Services AS, a firm consisting of independent petroleum engineers, geologists, geophysicists and petrophysicists, who was hired and compensated by us. The summary of this report is included as an annex to this offering memorandum. See "Annex A—Summaries of independent reserve reports."

Information in this offering memorandum includes a summary of a report, dated April 9, 2024, regarding estimates of our share of the reserves, contingent resources and PV-10 future net revenues from the Dome Patrol and Who Dat oil and gas fields. The report this summary is based on was prepared by our independent expert, Netherland, Sewell & Associates, Inc., a firm consisting of independent petroleum engineers, geologists, geophysicists and petrophysicists, who was hired and compensated by us. The summary of this report is included as an annex to this offering memorandum. See "Annex A—Summaries of independent reserve reports."

Information in this offering memorandum regarding the Brazil and US Gulf of Mexico offshore oil and gas industry and other related matters was derived from a report prepared by Wood Mackenzie, dated April 2024, an independent consultancy company specialized in the Brazilian and US oil and gas industry, who was hired and compensated by us. The report is included as an annex to this offering memorandum. See "Annex B—Brazil and US Gulf of Mexico Offshore Market Assessment."

Each of AGR Energy Services AS, Netherland, Sewell & Associates, Inc. and Wood Mackenzie has given and not withdrawn their consent to the inclusion of the summaries of their reports or their report, as applicable, their name and all references to them in this offering memorandum. Each of those reports speaks only as of the dates indicated therein and the independent consultants have no obligation to update such information.

CAUTIONARY NOTE REGARDING RESERVES AND CONTINGENT RESOURCES

This offering memorandum contains data relating to our petroleum reserves and contingent resources.

Unless otherwise stated, estimates of petroleum reserves and contingent resources are as of December 31, 2023. All estimates of petroleum reserves and contingent resources we report are prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator or evaluators. We prepare our petroleum reserves and continent resources estimates in accordance with the 2018 Petroleum Resources Management System ("PRMS 2018"). PRMS 2018 is sponsored by the Society of Petroleum Engineers. We follow the PRMS 2018 in order to comply with the ASX requirements for petroleum reserve and resource estimates for Australian publicly listed companies. Investors should note, however, that different petroleum reserves and contingent resources employ different assumptions. As a result, because of the impact of such assumptions, identical raw data can produce varying estimates of petroleum reserves and contingent resources. Our methodologies for classifying petroleum reserves and our petroleum reserves classifications vary in certain respects from the methodologies and classifications used by oil and gas companies subject to the reporting obligations of the SEC, including the reporting requirements set out in Regulations S-K and S-X under the Securities Act and related SEC disclosure requirements.

Estimates of petroleum reserves and contingent resources are largely dependent on the interpretation of data obtained from drilling, testing and production. These interpretations may prove to be incorrect over time and require revision. Estimates of proved reserves that may be developed and/or produced in the future are frequently based upon volumetric calculations and by analogy to similar types of reservoirs or geologic formations rather than upon actual production or injection history. Subsequent evaluation of the same reservoirs or geologic formations based upon actual production or injection rates and pressure information may result in revisions to the estimated proved or proved plus probable reserves. An estimate of petroleum reserves and contingent resources is based in part on a field's long-term development plan, and these estimates are classified or adjusted and re-classified as contingent where a long-term development plan has not been finalized or is not up-to-date or where the development plan is found to not be commercial. The estimation of petroleum reserves and contingent resources involves a significant degree of judgment by our management, engineers and technical personnel. These estimates are subject to various uncertainties, including those relating to the physical characteristics of oil and gas fields, changes in oil and gas prices and variable rock and fluid properties. These uncertainties are difficult to estimate and, as a result, actual production capacity may be materially different from current estimates of petroleum reserves and contingent resources. No assurance can be given that the petroleum reserves and contingent resources presented in this offering memorandum will be recovered or utilized at the levels presented. We have included in this offering memorandum estimates of our proved, or 1P, reserves, our proved plus probable, or 2P, reserves, our proved plus probable plus possible, or 3P, reserves and our probable, or 2C, contingent resources. Readers should carefully consider the definitions of these categories set out elsewhere in this offering memorandum and understand the degree of uncertainty attached to each category. Particular caution should be applied to our 3P reserve estimates and our 2C contingent resource estimates. 3P reserves includes estimated quantities of hydrocarbons the extraction of which we do not consider probable. Contingent resources are less certain than reserves. Our contingent resources are estimates of hydrocarbon quantities that are not recoverable under current conditions and may never become recoverable. These are contingent resources that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles. For contingent resources to move into the reserves category, the key conditions, or contingencies, that prevented commercial development must be clarified and removed. We would not be permitted to disclose our 3P reserves or 2C contingent resources in an SEC registration statement.

We engage independent experts as required to assist with the integrity of our reserves and contingent resources estimates. We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserves reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's independent reserves report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material.

For a discussion of how we estimate our petroleum reserves and contingent resources, including how we define "proved reserves," "probable reserves," "possible reserves" and "contingent resources" and some differences between our reserves reporting system and the SEC regulations, see "Reserves and contingent resources."

CAUTIONARY NOTE REGARDING PV-10 VALUES

We have included in this offering memorandum PV-10 values of our 1P, 2P and 3P reserves as calculated by our independent experts, AGR and NSAI. In preparing these PV-10 values, our independent experts have used their own estimates of our 1P, 2P and 3P reserves, which are different from what we estimate our reserves to be. For more information about our reserves estimates, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

PV-10 values are non-IFRS financial measures and represent the period-end present values of the estimated future cash inflows from the relevant reserves category less future development and production costs and discounted at 10% to reflect the timing of future cash flows. For more information about the inputs used by AGR and NSAI in preparing these PV-10 values, see their reports included in this offering memorandum in Annex A. AGR's and NSAI's PV-10 estimates do not use SEC pricing assumptions, and therefore cannot be reconciled to any IFRS or US GAAP measure, such as the standardized measure of discounted future net cash flows, which is the most directly comparable US GAAP financial measure to PV-10 values that are discounted using SEC pricing assumptions. Furthermore, US GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves. Because PV-10 estimates of 2P and 3P reserves are more uncertain than PV-10 estimates of 1P reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Nonetheless, we believe that PV-10 estimates for reserves categories other than proved reserves and using the pricing assumptions employed by our independent experts present useful information for investors about the future net cash flows of our reserves in the absence of a comparable IFRS or US GAAP measure such as the standardized measure of discounted future net cash flows.

Generally, PV-10, even when calculated using SEC pricing, is not equal to, or a substitute for, the US GAAP financial measure of standardized measure of discounted future net cash flows. The 1P, 2P and 3P reserve PV-10 values presented in this offering memorandum do not purport to present the fair value of our hydrocarbon reserves. However, our management believes that the presentation of PV-10 is useful because it presents the relative monetary significance of our properties regardless of tax structure. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our hydrocarbon gas properties. In addition, investors should be cautioned that estimates of PV-10 for 2P and 3P reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. For further discussion of the risks and uncertainties inherent in reserves and contingent resource estimations, see "Risk factors—Risks relating to our industry and operations—Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves no longer being commercially recoverable."

GLOSSARY

This Glossary sets forth the meanings of certain abbreviations and technical terms used in this offering memorandum. Certain financial terms are defined above under "Non-IFRS financial measures." Additional information regarding petroleum reserves definitions is contained in "Reserves and contingent resources."

A$ or AUD	Australian dollars.
AASB	Australian Accounting Standards Board.
amplitude	Amplitude is a measurement of the amount of energy transferred by a wave. Amplitude variation with offset is one of the main technologies of searching for oil and gas reservoirs.
ANP	Agencia Nacional do Petróleo, Gás Natural e Biocombustíveis (the Brazilian National Agency of Petroleum, Natural Gas and Biofuels).
API	The American Petroleum Institute gravity, or API gravity, is a measure of how heavy or light a petroleum liquid is compared to water.
ASX	The Australian Securities Exchange, operated by ASX Limited.
barrel or bbl	Barrel of oil, inclusive of condensate. A quantity of 42 United States gallons; equivalent to approximately 159 litres.
Baúna	Concession BM-S-40 containing the producing Baúna, Piracaba and Patola light oil fields in Brazil.
block	A license or concession area. It may be almost any size or shape, although usually part of a grid pattern.
bopd	Barrels of oil per day.
BP	BP Plc or BP Plc and its subsidiaries, as the context may require.
carbon neutral	Refers to having a balance between emitting and offsetting greenhouse gas emissions, achieved through acquiring carbon offsets in respect to our Scope 1 and 2 GHG emissions.
cash breakeven price	We calculate our cash breakeven price as the sum of our operating costs, royalties and other government take, transportation costs, other expenses (excluding depreciation and amortization – non oil and gas assets, share-based payments expense and realized losses on cash flow hedges) and our sustaining capital expenditure divided by our sales volumes in the period.
CNPE	Brazilian National Council for Energy Policy, a body subordinated to the President of Brazil and responsible for establishing the public policies related to the energy industry.

contingent resources........................	Those quantities of hydrocarbons 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 (as evaluation of the accumulation is insufficient to clearly assess commerciality). • 2C – Denotes best (P50) estimate of contingent resources.
CO2e..	Carbon dioxide equivalent.
discovery well................................	The first successful well on a new prospect.
EBITDA...	Earnings before Interest, Taxes, Depreciation, and Amortization.
ESG	Environmental, social, and governance.
exploration	The process of identifying, discovering and testing prospective hydrocarbon regions and structures, mainly by interpreting regional and specific geochemical, geological, geophysical survey data and drilling.
FID	Final Investment Decision.
field	An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area although it may refer to both the surface and underground productive formation.
fixed remuneration	Relates to fixed cash remuneration consisting of base salary and superannuation contributions/pension contributions.
floating production system uptime..	We calculate the uptime rate for the Who Dat floating production system by dividing the number of days with production by the number of days in the given time period, excluding scheduled downtime.
floating production, storage and offloading facility efficiency rate....	We calculate our efficiency rate for the Baúna floating production, storage and offloading facility as actual production divided by our reservoir production forecast, limited to 100%.
FPS	Floating Production System.
FPSO	Floating production, storage and off-loading facility.
GHG	Greenhouse gas.
GST	Goods and Services Tax in Australia.
HSSE	Health, safety, security and environment.
IBAMA..	Brazilian Institute of Environment and Renewable Natural Resources.

m	Million.
Mgal	Million of gallons (1,000,000 gallons).
MMbbl	Millions of barrels (1,000,000 barrels).
net revenue interest or NRI	Our working interest net of royalties charged by the American Office of Natural Resources Revenue and third-party royalties.
net working interest or NWI	Our working interest prior to any royalties being deducted.
net zero	Refers to the reduction of Scope 1 and 2 GHG emissions as far as possible and offsetting the residual greenhouse gas emissions through investment in carbon removal or sequestration initiatives equal or greater to the residual greenhouse gas amount.
OMS	Operating Management System.
performance rights	Performance rights issued under Karoon Energy's performance rights plan.
Petrobras	Petróleo Brasileiro SA.
prospect	A geological or geophysical anomaly that has been surveyed and defined to the degree that its configuration is fairly well established, and on which further exploration such as drilling can be recommended.
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. • 1P – Denotes low (P90) estimate of reserves. • 2P – Denotes best (P50) estimate of reserves. • 3P – Denotes high (P10) estimate of reserves.
reservoir	A porous and permeable rock formation to store and transmit fluids such as hydrocarbons and water.
SWST	Shell Western Supply and Trading Limited (a member of the Royal Dutch Shell Plc group).
SOFR	Secured Overnight Financing Rate.
tCO2e	Tonnes of carbon dioxide equivalent.
US$	United States dollars.
Williams	Williams Companies, Inc. or Williams Companies, Inc and its subsidiaries, as the context may require.

SUMMARY

This summary highlights selected information from this offering memorandum and does not contain all of the information that may be important to you. This summary does not purport to be complete and is qualified in its entirety by reference to, and should be read in conjunction with, the more detailed information appearing elsewhere in this offering memorandum. You should read this entire offering memorandum carefully, including the risk factors and financial statements included in this offering memorandum.

Overview

We are an international offshore upstream oil and gas production and exploration company headquartered in Melbourne, Australia, with assets in Brazil and the United States of America. In Brazil, we own and operate the producing Baúna, Piracaba, and Patola fields, which we refer to as Baúna, and are party to concession agreements, in the Santos Basin. In the United States of America, we own non-operated interests in the producing Who Dat, Dome Patrol, and Abilene oil and gas assets, which we refer to as Who Dat, as well as interests in exploration licences, located in the US Gulf of Mexico. Our assets are diversified geographically with multiple producing wells in the Santos Basin and US Gulf of Mexico, which are prolific, globally recognized hydrocarbon basins providing us with the opportunity to increase our reserves and resources. At December 31, 2023, we had production from six oil fields and 19 producing wells, and eight pre-development and exploration blocks.

Our assets have demonstrated predictable reservoir characteristics and provide us with a high quality marketable product, as reflected in its sales prices. Our assets have relatively low production costs and low sustaining capital expenditure requirements compared to the overall oil and gas sector, resulting in a track record of our assets being highly cash generative with strong levels of free cash flow. We are also able to leverage our technical expertise and experience across our assets.

Our strategy is focused on delivering safe and reliable operations and value accretive growth through investment in our producing assets, development of in-field and near-field opportunities, and acquisitions intended to deliver us a material increase in the scale of our production. We have a track record of safe, efficient operation, and asset enhancement as an operator.

We believe, due to the quality of our existing assets, that our in-field and near-field drilling programs (which are in proximity to our existing producing assets) provide us with the potential to replace and increase our reserves and resources. We have increased production through the delivery of a workover program and development campaign in our Santos Basin assets, which were completed on time and on budget. See also "Business—Our production and exploration assets—Brazil—Producing assets—Baúna."

We have pursued value accretive growth through our acquisition of Who Dat in December 2023, which was funded through available cash, an equity raise, and drawings from our debt facility. We believe our financial policies are prudent relative to our peers, as evidenced by our low leverage. We are committed to delivering our growth strategy while maintaining financial discipline and a strong balance sheet.

We intend to continue to evaluate acquisition opportunities, focusing primarily on producing assets offshore the United States and Brazil that would increase our production, operating cashflow and profitability. Assets in these geographies would enable us to leverage our presence in Houston and Rio de Janeiro and our technical expertise in the region, as well as potentially providing opportunities to use existing infrastructure. However, we may also examine acquisition opportunities in other locations and at different stages of development.

In the 12 months to December 31, 2023, we generated revenues of US$680.0 million, underlying EBITDA of US$429.0 million, and cash flows from operating activities of US$442.2 million. On a pro-forma basis, assuming we owned the Who Dat assets since January 1, 2023, in the 12 months to December 31, 2023 we had revenues of US$827.4 million and underlying EBITDA of US$548.9 million. See "Unaudited pro forma combined financial information" and "Selected unaudited pro forma combined financial information." At December 31, 2023, our PV-10 calculations on a 2P basis, according to AGR and NSAI for our Baúna and Who Dat assets totalled US$2,075 million[1] and we estimated our net oil and gas 2P reserves to be 77.5 MMboe.[2]

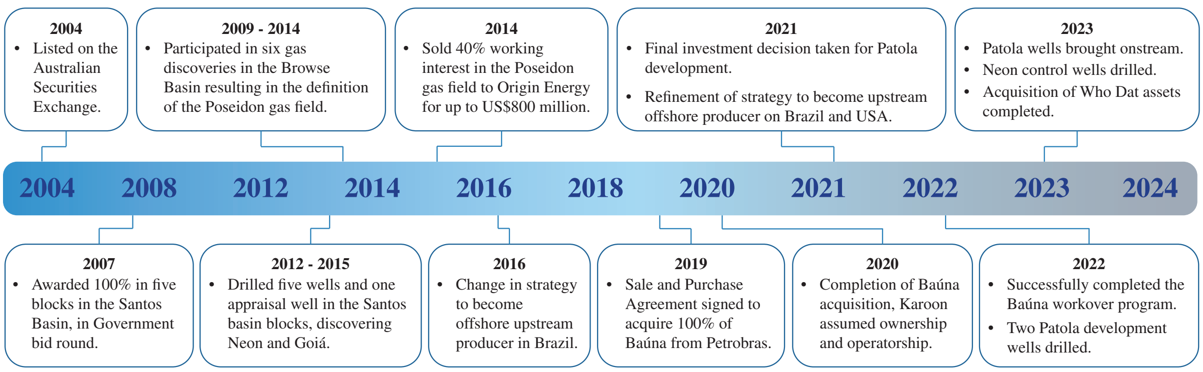
We are headquartered in Melbourne, Australia, and we have regional offices in Houston, United States of America, and Rio de Janeiro, Brazil. We listed on the Australian Securities Exchange in 2004, and as of April 19, 2024, we had a market capitalization of A$1.7 billion (US$1.1 billion)[3], and employed more than 120 employees.

Company history

In our 20 years since listing on the Australian Securities Exchange, we have grown from our origins as an Australian focused oil and gas explorer to become a diversified oil and gas production and exploration company. We achieved this through the completion of two transformational acquisitions, namely the acquisition of Baúna in 2019 and its subsequent development and expansion, and the acquisition of the Who Dat assets in 2023.

The following chart shows a number of our key corporate milestones.

Company History



Our production and exploration assets

We have two main production assets comprising six operating oil fields. Our wholly owned and operated producing asset Baúna located in the southern Santos Basin, offshore Brazil and our non-operated interests in the Who Dat producing assets located in the US Gulf of Mexico, offshore Louisiana, United States of America.

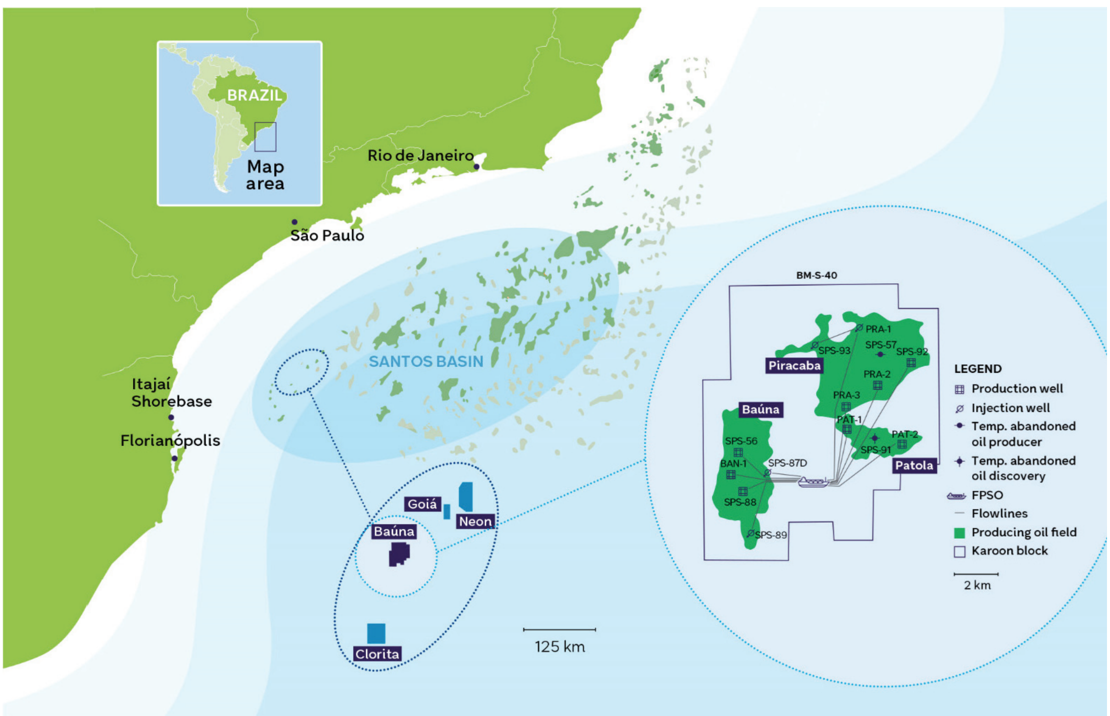
1 See "Cautionary note regarding PV-10 values" for further information on our PV-10 figures.
2 For more information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."
3 A$ translated to US$ at the Reserve Bank of Australia rate for April 19, 2024 of A$1.00 = US$0.6397.

Our Assets and Working Interests

Baúna – Brazil

We acquired Baúna from Petrobras in 2019 for US$380 million, plus additional oil-price linked contingent payments of up to US$285 million. Baúna is a conventional offshore oil operation located in the BM-S-40 production license in approximately 300 meters of water, approximately 210 kilometers offshore Brazil. Baúna comprises 7 producing wells (and 1 additional production well that is currently shut in) which are connected through sea-bed flowlines to a floating production, storage and offloading facility, the *Cidade de Itajaí*, which we charter from and which is owned by Altera & Ocyan. The floating production, storage, and offloading facility has a nameplate capacity of approximately 80,000 barrels of liquid per day and storage capacity of 631,000 bbl of oil.

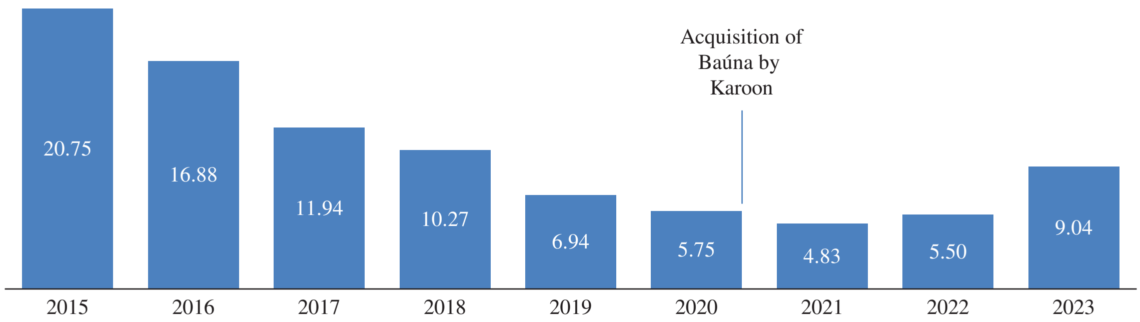
Santos Basin – Location of Baúna



Production History and Performance

Since we acquired Baúna and took operatorship in November 2020, we have increased the average daily production rate from 14,800 bopd[4] in the quarter ended December 31, 2020, to 27,500 bopd in the quarter ended December 31, 2023, an increase of 86%. The chart below illustrates the production improvements achieved due to our investment in Baúna through the workover program and Patola development, described further below.

Baúna Production History (MMbbl)[5]



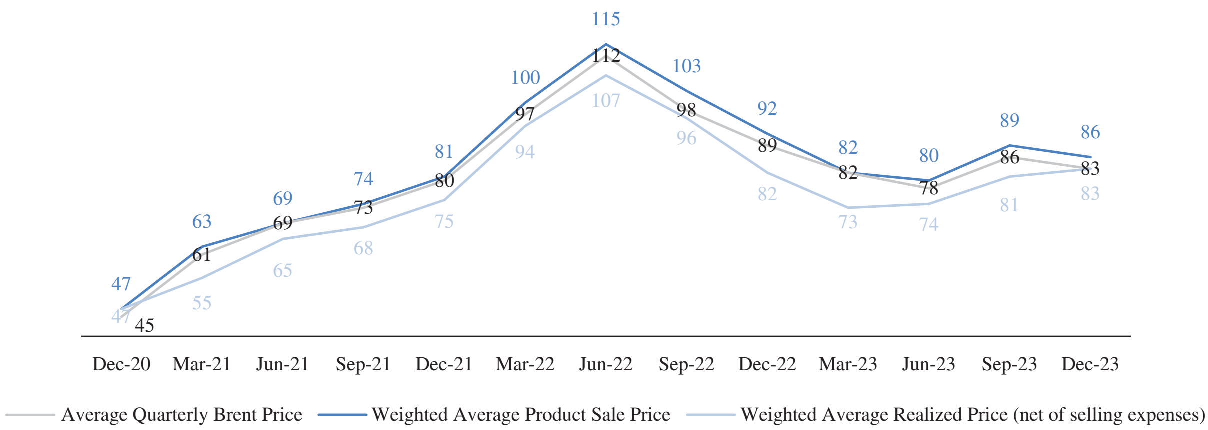
Our floating production, storage, and offloading facility is owned by Altera & Ocyan and has historically achieved high levels of efficiency, averaging 95% over the period from November 7, 2020, when we commenced as operator of Baúna, to December 31, 2023, excluding the March 2023 shutdown, and 91% including the shutdown.[6] In March 2023, following the identification of a gas leak resulting in a temporary shutdown, we decided in consultation with Altera & Ocyan to undertake a comprehensive inspection of the pipework on the floating production, storage, and offloading facility. All identified repairs, maintenance or replacements were conducted over a six-week period, resulting in lower facility efficiency during this time period.

Products and Pathway to Market

Baúna produces a light sweet crude that is high quality, as reflected in its sales prices. Since our acquisition of Baúna, to December 31, 2023, we have averaged a sale price of US$84.92 per bbl which represents a premium to the average Brent price on a delivered basis and which corresponds to an weighted average realized price (net of selling expenses) discount of 4.7% to Brent over the corresponding period. All of our production from Baúna is sold under an offtake and marketing agreement to a wholly owned subsidiary of Royal Dutch Shell Plc ("Shell"). Our counterparty risk under the offtake agreement is with this subsidiary of Shell.

4 Reflects operations from November 7, 2020 to December 31, 2020.
5 Source: Historical data prior to our acquisition provided by Petrobras and as published by ANP.
6 We calculate our efficiency rate for Baúna as actual production divided by our reservoir production forecast, limited to 100%. Historical efficiency rates are not indicative of future performance.

Average Quarterly Brent Price, Weighted Average Product Sale Price, and Weighted Average Realized Price (net of selling expenses) (US$/bbl)[7]



Since our acquisition of Baúna, more than 45 cargoes have been sold to 11 refineries that are located across four continents. Our strategy involves continuing to develop the global market for Baúna crude so as to optimize our realized net back price.

In-field and Near-Field Development

At the time we acquired Baúna, it was producing 14,800[8] bopd and had 2P Reserves of 39.2[9] MMbbl. We identified enhancement opportunities in Baúna which we believed would increase production and reserves and, following 18 months of detailed planning, we undertook a workover program at Baúna from May 2022 to September 2022. The workover program comprised the installation of new electric submersible pumps in two wells (PRA-2 and SPS-92) and the installation of gas lift equipment in a third well (SPS-56). As a result of the workover program, we materially increased production. The workover program, together with the development of the Patola field at Baúna resulted in an increase in our average daily production from 14,600 bopd in March 2021, to a peak average daily production of 34,500 bopd in July 2023. In addition, the workover program and the Patola development increased our 2P reserves by 28.9 MMbbls between December 31, 2020 and December 31, 2022 (not considering reductions through production from Baúna over that same period).

In June 2021, we took the final investment decision to proceed with the development of the Patola field. The Patola development comprised drilling two production wells and installing wellheads and subsea production infrastructure including flowlines and umbilicals that connect to the floating production, storage, and offloading facility. The Patola development resulted in a material increase in our production and reserves. We achieved first oil in March 2023.

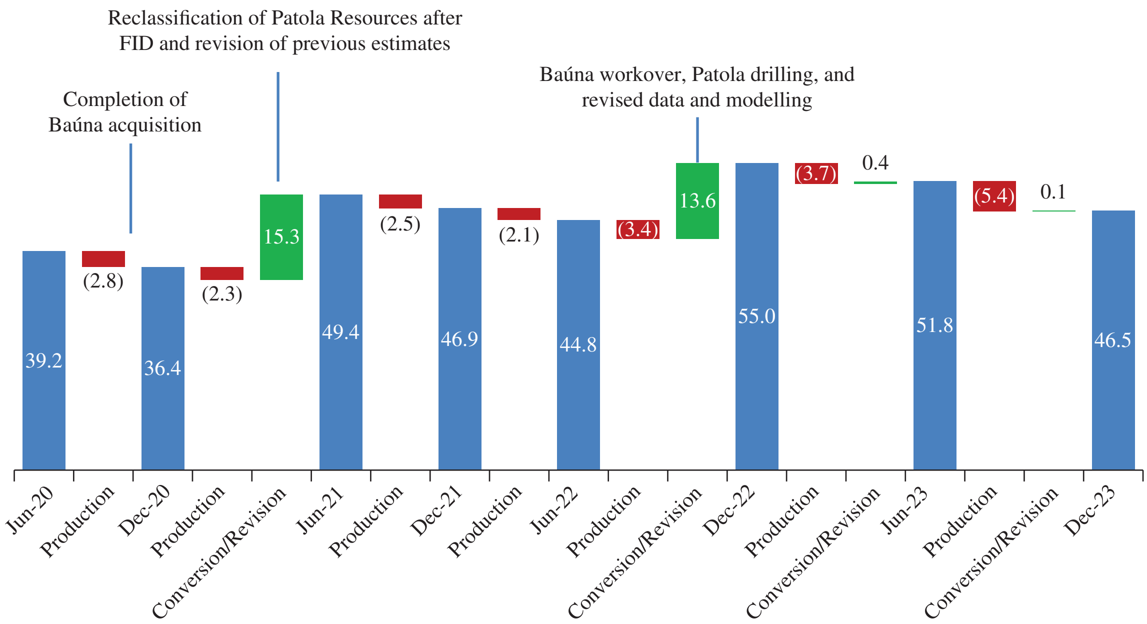
We have a track record of delivering these enhancements in accordance with our planning, with both the workover program and Patola development being delivered safely, on time, and within budget.

7 The average Brent price for the quarter ended December 31, 2020 reflects the average published Brent crude oil price over the quarter ended December 31, 2020, noting that our operations commenced on November 7, 2020. We shipped our first cargo in December 2020. Karoon realized price is defined as weighted average realized price (net of selling expenses). Product sale price is defined as the weighted average actual price achieved for Baúna crude based on an agreed premium or discount benchmarked to the Brent crude oil price.

8 Reflects operations from November 7, 2020 to December 31, 2020.

9 Independent reserves report as of July 1, 2020, prepared by AGR Petroleum Services Reservoir Management Division.

Increase in Baúna 2P Reserves (MMbbl)



Nearby Baúna, we own 100% of each of the Neon and Goiá discoveries. We acquired a 100% interest in the Neon and Goiá blocks through participation in a government tender in 2007. Neon is located 60 kilometers north-east of Baúna and was discovered in 2015. During the second quarter of 2024, we approved the progression of the Neon discovery into the "concept select phase", the second stage of our project maturation process. Goiá is located 50 kilometers north-east of Baúna and was discovered in 2013, and appraised with an additional well in November 2014. Initial tests for these wells showed the potential for high initial flow rates of 33 and 39 degrees API oil. As a result of these tests, we were able to assign contingent resource estimates to Goiá in 2015.

Exploration Opportunities

We also 100% own and operate block S-M-1537, containing the Clorita prospect, located 50 kilometres south of Baúna, and are currently undertaking desktop geological and geophysical studies in connection with this block. In addition, we successfully participated in a government bid round to acquire 100%[10] interests in two deepwater blocks in the Santos Basin in December 2023. These two blocks, S-M-1356 and S-M-1482, lie approximately 80 kilometers southeast of Baúna.

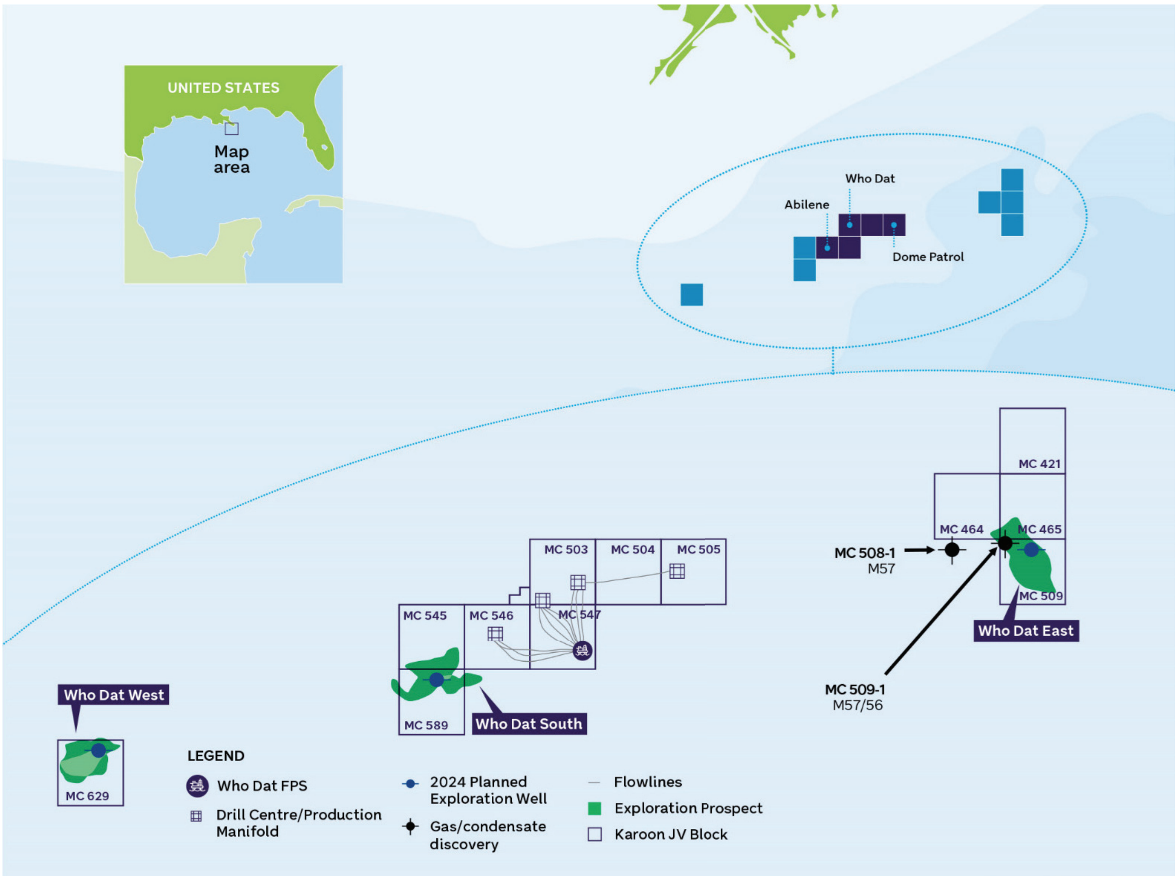
Who Dat – United States of America

In the United States of America, we own non-operating interests in offshore producing assets comprising the Who Dat, Dome Patrol, and Abilene oil and gas fields which we acquired from LLOG Exploration Offshore, LLC and LLOG Omega Holdings (collectively, "LLOG") in December 2023, for US$720 million and a commitment to fund up to US$39.2 million of LLOG's share of capital expenditure on Who Dat East, and Who Dat West exploration wells.

10 Karoon successfully bid to secure 100% interest in deepwater blocks S M 1356 & S M 1482. Formal granting is subject to certain conditions expected to be satisfied by June 30, 2024.

Who Dat is a conventional deepwater oil and gas operation, which management believes is a high quality, low cost operation. It is located at a depth of approximately 800 meters, offshore from Louisiana, and is operated by LLOG, a private independent US operator with extensive technical expertise and experience. Production from Who Dat ties back to the Who Dat floating production system which has a nameplate capacity of 40,000 bopd and 150 MMscfpd. Our Who Dat assets are subject to conventional US Gulf of Mexico deepwater joint operating agreements. See "Business—Our production and exploration assets—United States of America—Joint venture partners" for additional information on our joint operating agreements.

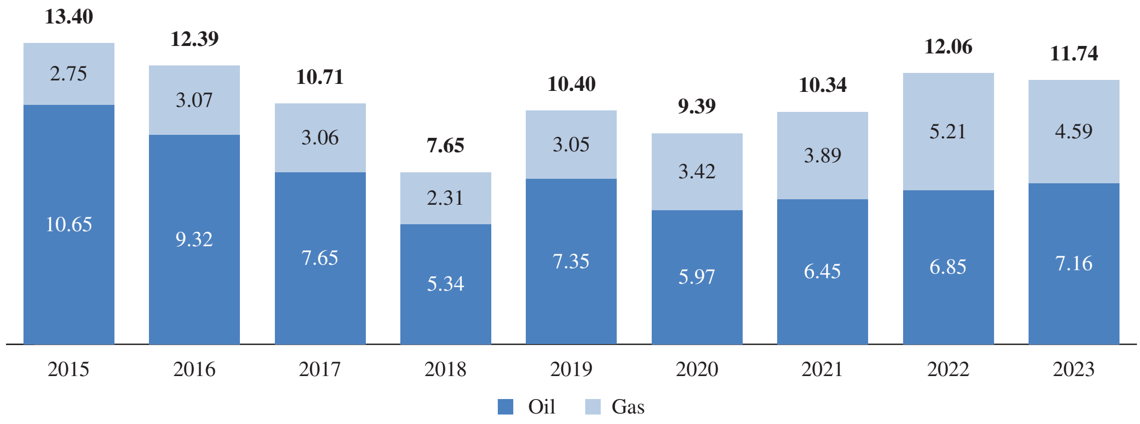
US Gulf of Mexico – Location of Who Dat



Production History and Performance

Historically, the Who Dat assets have exhibited stable and reliable production which has been achieved through LLOG's in-field and near-field development program, including a new well that came online in July 2023, a sidetrack that came online in August 2023, new subsea pump which came online in September 2023, and a sidetrack and a new well that both came online in February 2024.

Who Dat Historical Production (MMboe)[11]



The Who Dat floating production system has historically had a stable and reliable operating profile. Since commercial production began in 2011 to March 31, 2024, the facilities have achieved an average uptime of 94%[12].

Products and Pathway to Market

Production from Who Dat ties back to the Who Dat floating production system from which it is transported through the Mars pipeline to our offtakers and is marketed as Mars grade and sold at a price equal to WTI crude oil as adjusted for the published Mars differential. This provides us with the ability to sell our production to multiple potential counterparties and refineries and diversify our offtakers, while optimizing our realized price.

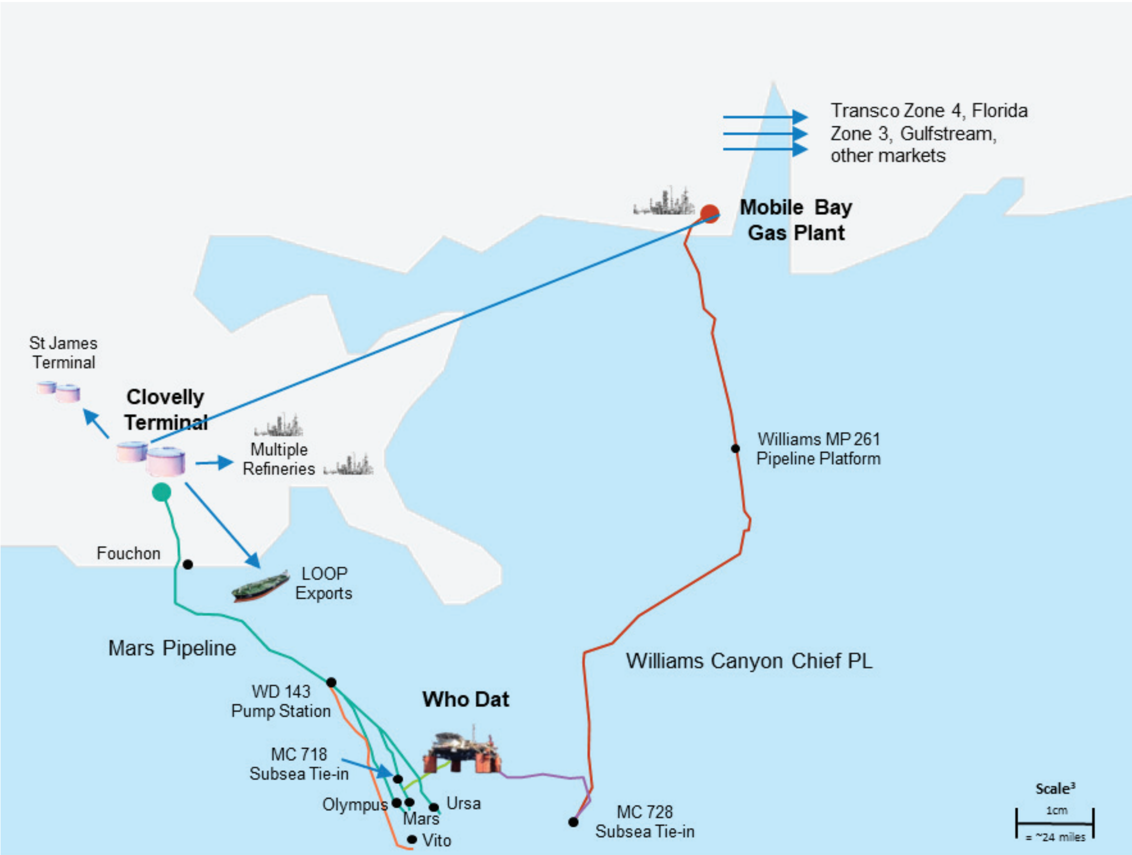
Gas is transported through a Who Dat-owned lateral pipeline into the Canyon Chief pipeline, an offshore gathering system, and then delivered to the Transcontinental Gas pipeline. The Transcontinental Gas pipeline provides service to the Williams Mobile Bay gas plant, and then into multiple onshore markets. Who Dat gas is typically priced off Platt's Florida Zone 3 or Transco Zone 4 index, which are reference prices for gas in the Louisiana/Southeast region of the United States.

All of our oil, gas and natural gas liquids production from Who Dat is currently sold under offtake agreements with wholly owned subsidiaries of BP or Williams and our counterparty risk under the offtake agreements are with these subsidiaries of BP and Williams, respectively.

11 Historical production shown on a gross basis. Historical production data provided by LLOG.

12 Uptime is defined as the number of days the Who Dat facility is producing divided by the number of days in the given time period, excluding all scheduled downtime. Source: Historical production data provided by LLOG. Historical uptime rates are not indicative of future performance.

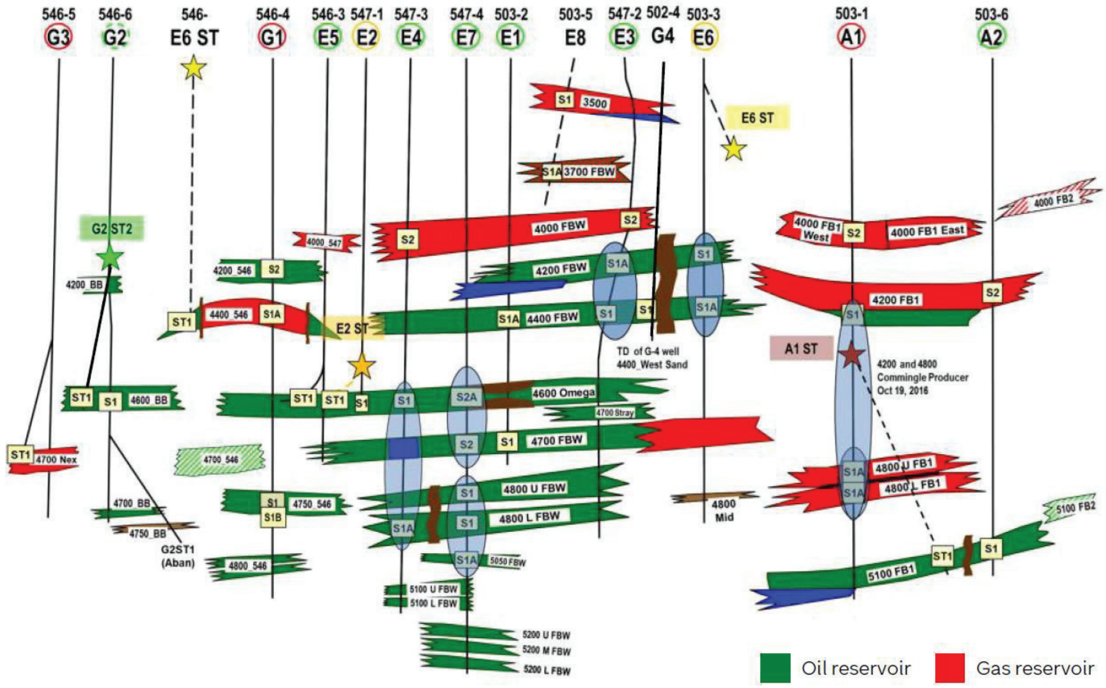
Who Dat Pathway to Market



In-field and Near-field Development

The Who Dat reservoir is characterized by stacked pay opportunities, which refers to the presence of multiple potential producing formations beneath a given surface location. We believe these opportunities allow for relatively low cost development and replacement of reserves, which supports us in prolonging the life of our operating fields. The joint venture's workover and drilling opportunities are amplitude-supported and calibrated by nearby wells and proven reservoirs, which has historically led to high workover and drilling success rates. The joint venture's exploration targets are extensions of known productive reservoir units in Who Dat and exhibit analogous subsurface characteristics based on seismic data sets.

Who Dat Reservoir Unit Cross Section



We also have varying interests in possible near-field opportunities, including Who Dat East, Who Dat West, and Who Dat South. The joint venture intends to drill an appraisal well at Who Dat East starting in late April 2024. We expect an exploration well to be drilled at Who Dat South in the second half of 2024, and subject to approval by the joint venture partners, a second exploration well to be drilled at Who Dat West, also during the second half of 2024. All three of these opportunities are within tie-back distance of the Who Dat floating production system. Within the Who Dat East permit, there is also a deeper Cretaceous gas target for which seismic studies are ongoing.

Our reserves and resources

As of December 31, 2023, our 2P reserves and 2C resources were estimated to be 78 MMboe and 103 MMboe.[13] Our strategy focuses on expanding our 2P reserves through (i) the continued development of our existing producing assets, (ii) our in-field and near-field drilling programs which focus on converting resources to 2P reserves, (iii) identification of new discoveries which are adjacent to our existing assets, and (iv) acquisitions which align to our strategy and our investment criteria.

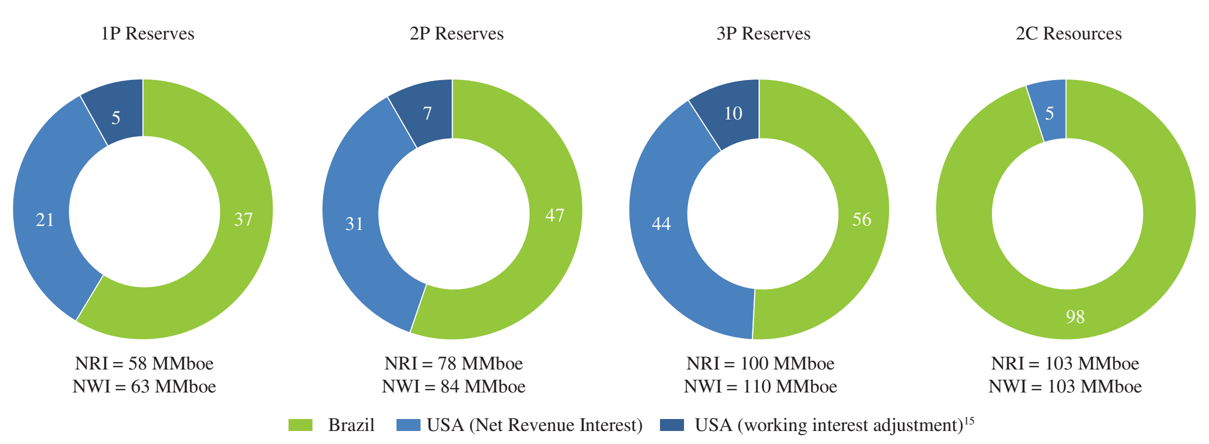
From December 31, 2020 to December 31, 2023, and excluding the impact of the Who Dat acquisition, we achieved a reserves replacement ratio[14] of 152%. Including the impact of the Who Dat acquisition, we have increased reserves over that period by 113%.

13 We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserve reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's independent reserve report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

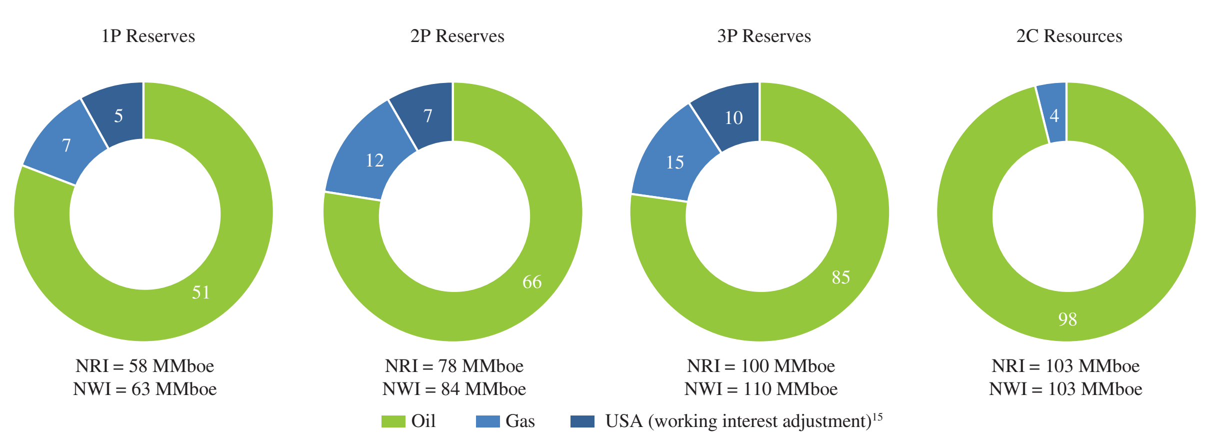
14 We define reserves replacement ratio as 2P reserves additions during the period from December 31, 2020 to December 31, 2023 divided by production over the same period.

The following charts show our reserves and contingent resources by country and by product on a net revenue interest basis ("NRI") and a net working interest basis ("NWI") as of December 31, 2023. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources" for additional information.

Reserves and Contingent Resources by Country (MMboe) – as of December 31, 2023[15]



Reserves and Contingent Resources by Product (MMboe) – as of December 31, 2023[15]



Our strengths

We are a diversified independent oil and gas production and exploration company that is strategically focused on growth in the United States of America and Brazil. Our strategy, which we call "50 for 10", involves us growing our scale to achieve a minimum production of 50,000 boepd which we aim to sustain for no less than a 10 year period. We believe that our high quality assets, technical expertise, experienced board and management, and strong financial position with a robust balance sheet and strong free cash flow will support us in achieving our strategy, and our objective to grow our production and reserves.

15 As royalties can be taken in kind in the United States, the Who Dat working interest adjustment reflects the royalty component of reserves at Who Dat in order to present reserves and resources from Baúna and Who Dat equivalently, on a pre-royalties basis.

We believe that our competitive strengths include:

We are an independent oil and gas company with high quality, conventional, low cost assets with low sustaining capital expenditure requirements and in-field and near-field production growth opportunities.

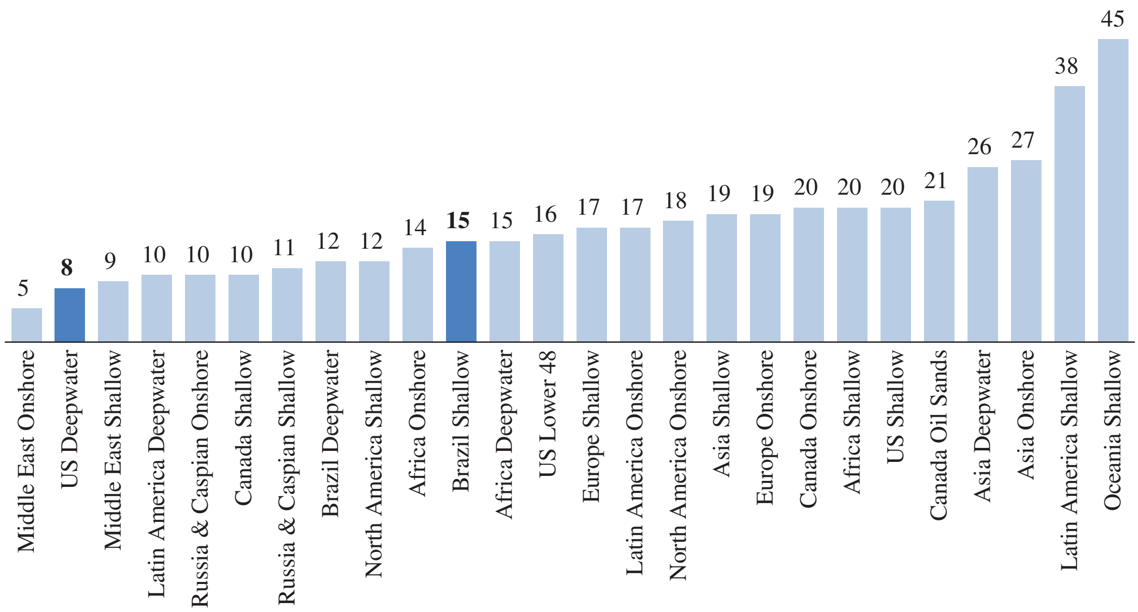
Our assets are conventional offshore assets, which management believes are high quality and low cost, and which are in geographic locations that have extensive seismic information. Both the Baúna and Who Dat fields have a long production history and reservoir characteristics that are well understood by our technical teams, comprising our geoscientists and engineers. The predictability of our reservoirs helps us forecast production and cashflows.

Our assets are located in prolific hydrocarbon basins that have proven and well-understood subsurface characteristics. Our assets have in-field and near-field growth opportunities that provide potential to increase our production volumes and reserves, including through potential tie backs to our floating production and storage facilities. Employing tie backs would leverage our existing infrastructure, reducing our capital expenditure when developing assets, enabling us to increase production and reserves in a capital efficient manner and increase our free cash flow generation and profitability.

Our assets have relatively low production costs and low sustaining capital expenditure requirements compared to the overall oil and gas sector. During 2023, Baúna and Who Dat had average unit production costs of US$12.4/boe and US$7.9/boe, respectively. Given our relatively low capital expenditure requirements, on a portfolio basis, our cash breakeven price[16] was US$22.40/boe during TY23.

Wood Mackenzie has prepared the below three-year aggregate unit production costs forecast (including transportation costs). Our unit production costs broadly align with the ‘US Deepwater’ and ‘Brazil Shallow’ categories, under which our operations are classified. According to Wood Mackenzie, these provide a proxy for the short-run marginal costs for onstream production across different resource themes and regions, and low operating expenditures reflect greater near-term resilience to commodity price declines for onstream assets.

Wood Mackenzie Unit Production Cost[17] by Resource Theme, 3-yr Aggregate Forecast per Barrel Expenditure 2024-2026



16 We calculate our cash breakeven price as the sum of our operating costs, royalties and other government take, transportation costs and other expenses (excluding depreciation and amortization – non oil and gas assets, share-based payments expense and realized losses on cash flow hedges) and our sustaining capital expenditure divided by our sales volumes in the period.

17 Source: Wood Mackenzie; Onstream, commercial liquids fields with remaining liquids resource > 25mmbbl. Unit production costs as defined only include fixed and variable operating expenses, transportation tariffs, and leasing costs. Royalties and G&A expenses are excluded from the unit cost. See “Cautionary note regarding industry and third-party data” and Annex B.

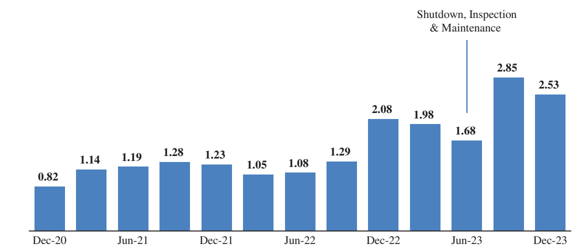
Wood Mackenzie, based on its analysis, considers that absolute demand growth coupled with a forecast supply gap provides a positive environment for long-term oil prices, which it forecasts to range from US$80/bbl to US$84/bbl (in real terms, 2023) between 2025 to 2035. If we are able to maintain our cash breakeven price and Wood Mackenzie's outlook proves accurate, it would allow us to generate strong cash margins and provide us with financial resilience to withstand material downturns in oil prices.

Our producing assets are strategically located in prolific hydrocarbon regions, and have a track record of predictable and efficient production.

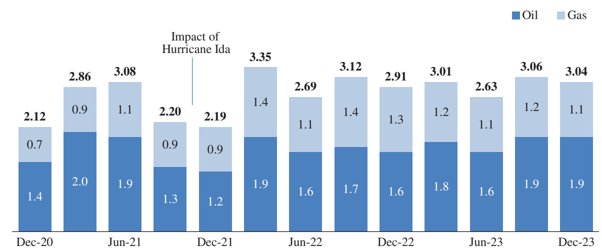
Our assets are located in the Santos basins and the US Gulf of Mexico, two regions that are recognized globally as prolific hydrocarbon basins. We believe that our strategic focus in these regions allows us to realize financial and operational synergies including: (i) the geological properties and reservoir characteristics of our assets are similar, allowing us to leverage our technical expertise and the experience of our geoscientists and engineers across our portfolio, (ii) integration of operating teams and centralization of logistics with proximity of teams located in similar time zones, (iii) synergies in managing supplier and customer relationships, delivering efficiencies and realizing economies of scale due to the increased size of our operations, and (iv) within each region, established infrastructure and pipelines which may reduce development costs and capital expenditure. We believe the strategic location and proximity of our assets contribute to our ability to generate strong free cash flows.

Our assets, which management believes are high quality, have reservoir characteristics that are well understood, and use conventional oil and gas extraction methods, which have historically resulted in predictable production.

Baúna – Quarterly Production History (MMbbl)



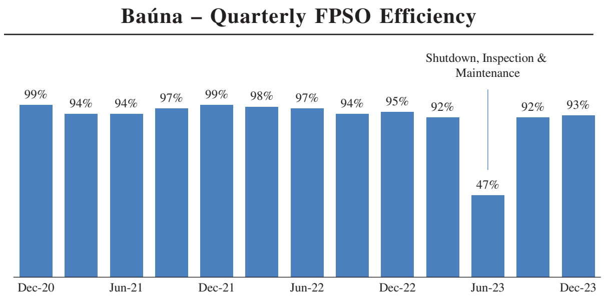
Who Dat – Quarterly Production History (MMboe)[18]

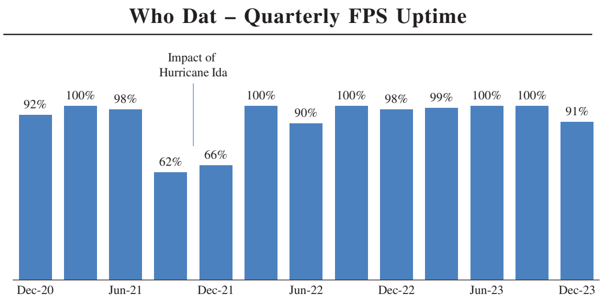


Our Baúna floating production, storage and offloading facility has achieved an average efficiency rate of 95%[19] over the period from November 7, 2020, when we commenced as operator of Baúna, to December 31, 2023. The Who Dat floating production and storage facility has achieved an average uptime rate of 94% since inception, being December 10, 2011 to March 31, 2024. During the quarter ended December 31, 2023, our joint venture partners undertook remediation works for corrosion under insulation on an oil treater degasser, which we use to remove gases from our crude oil, resulting in the lower facilities uptime of 91%.

18 Gross production volumes. Source: Historical production data provided by LLOG. During 2021, Hurricane Ida caused 66 days of unplanned downtime as a result of pipeline damage in a downstream facility.

19 Excluding the March 2023 shutdown. See also "Business—Our production and exploration assets—Brazil—Producing assets—Baúna. Including the shutdown, the facility achieved an average efficiency of 91%.

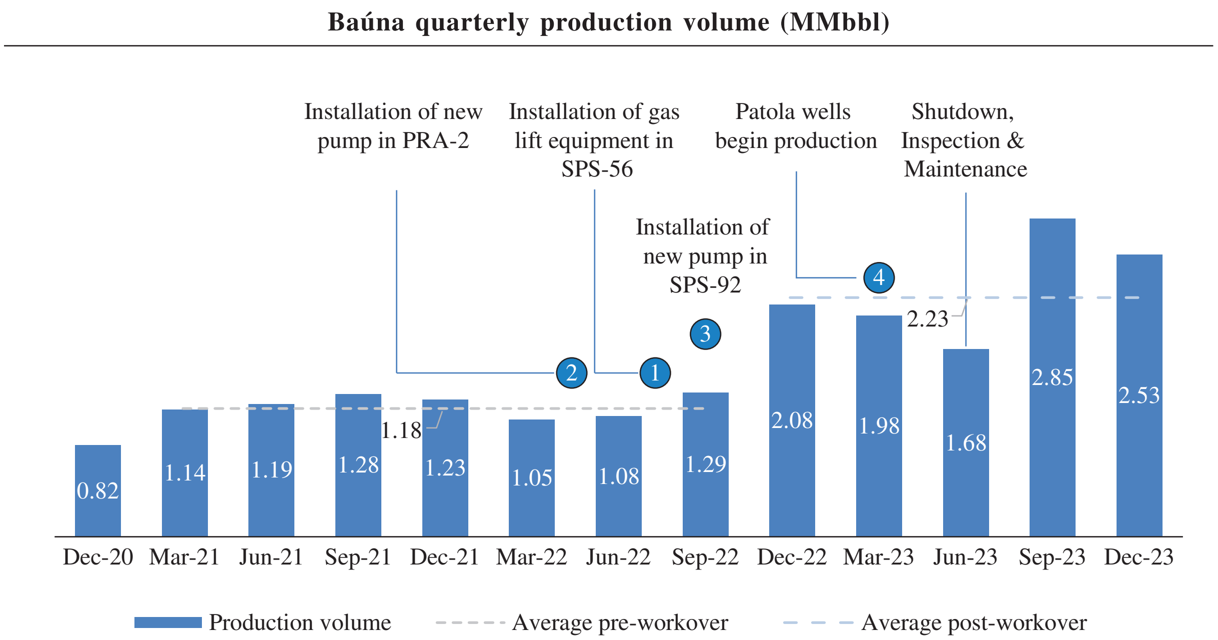




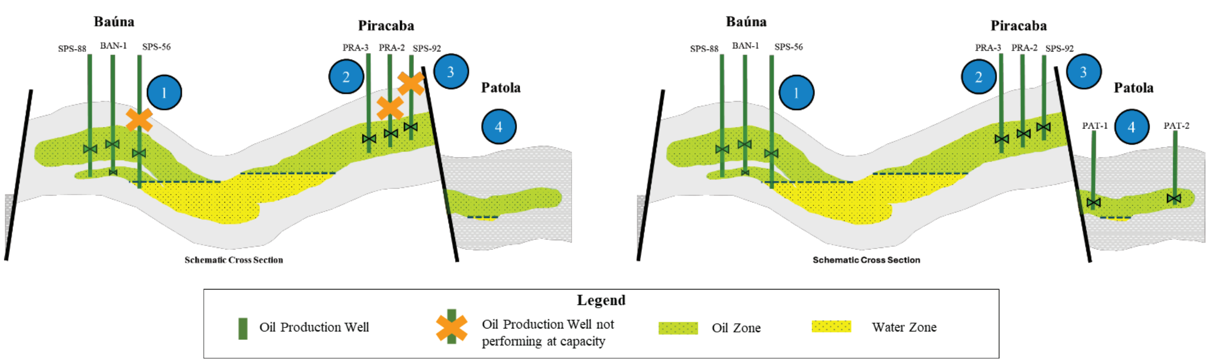
We have a strong track record as an operator, proven history of asset enhancement, and demonstrated technical expertise in the oil and gas industry.

We have considerable experience and technical expertise, and have demonstrated our ability as an operator through our performance at Baúna. Since taking operatorship in November 2020, we have enhanced our asset base, having materially grown production through our workover programs and increased reserves through our in-field and near-field drilling programs. Excluding our six-week shutdown in the first half of 2023, we have also maintained high efficiency rates for the floating production, offload and storage facility at Baúna.

We undertook a workover program at Baúna from May 2022 to September 2022, replacing two electric submersible pumps and installing gas lift equipment, and delivered the development of Patola. This resulted in an increase in our average daily production from 14,600 bopd in March 2021, to a peak average daily production of 34,500 bopd in July 2023. Our workover program and the Patola development increased our 2P reserves by 28.9 MMbbls between December 31, 2020 and December 31, 2022 (not considering reductions through production from Baúna over that same period).



Baúna prior to workover and Patola drilling | **Baúna after workover and Patola drilling**



We have strong relationships with our key business partners, and sell our production through marketing and offtake agreements to investment grade counterparties.

We aim to maintain strong and collaborative relationships with business partners, including our key stakeholders Shell, BP, LLOG and Westlawn.

Offtakers

Brazil – Production offtake arrangements with Shell

- Our production from Baúna is sold under a marketing and offtake agreement with Shell Western Supply and Trading Ltd ("SWST"), a wholly-owned subsidiary of Royal Dutch Shell Plc.
- Under the terms of our marketing and offtake agreement, we receive payment from SWST. Shell currently has credit ratings of Aa2 (stable), A+ (stable), AA- (stable), from Moody's, S&P and Fitch, respectively, and is the 5th largest oil and gas company globally by market capitalization.
- We renewed our marketing and offtake agreement with SWST in November 2023, and SWST has been a lender under our RBL facility since October 2019.

US Gulf of Mexico – Production offtake arrangements with BP and Williams

- We sell our share of crude oil from Who Dat to BP Products North America Inc., a member of the BP Plc group under a month-to-month evergreen crude oil purchase agreement. We sell our share of natural gas from Who Dat on a six-month seasonal contract basis to BP Energy Company, also a member of the BP Plc group under a gas purchase contract.
- BP Plc, which currently has credit ratings of A1 (stable), A- (positive), A+ (stable) from Moody's, S&P and Fitch, respectively. BP Plc is the 9th largest oil and gas company globally by market capitalization. BP Products North America Inc. and BP Energy Company have parent guarantees from BP Plc.
- We sell our share of natural gas liquids from Who Dat under a life-of-asset sales agreement at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation to Williams Field Services, a U.S. based natural gas infrastructure provider.

Operators & Partners

Brazil – Altera & Ocyan as owner and operator of the floating production, storage, and offloading facility

- Altera & Ocyan is a joint venture between Brazilian company, Ocyan, and Norwegian-headquartered, Altera Infrastructure, that owns and operates the floating production, storage and offloading facility at Baúna.

- We collaborate with Altera & Ocyan to manage required maintenance and enable continuous production.

- In December 2023, EIG Global Energy Partners ("EIG"), a global energy and infrastructure investor, entered into definitive agreements to acquire Ocyan. EIG has significant investments in infrastructure supporting crude oil production.

- See "Risk factors—Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan."

US Gulf of Mexico – LLOG as operator and joint venture partner

- Our assets in the US Gulf of Mexico are operated by LLOG, a private independent US operator with extensive technical expertise and experience.

- At the time we acquired our interests in the Who Dat assets, LLOG has advised that it had drilled 308 wells in the Gulf of Mexico since 2002, including 116 wells in deep water, and 14 wells at Who Dat.

- LLOG management has a history of performance, and we have a collaborative relationship.

US Gulf of Mexico – Westlawn as joint venture partner

- Westlawn Group is a private investment firm based in Houston, Texas, focused on long-term investment in the oil and gas industry.

- Westlawn is a joint venture partner in Who Dat. Westlawn's management team is well known to us and we have a collaborative relationship.

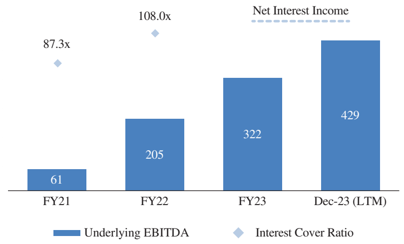
We believe our financial policies are prudent and we have delivered growth while maintaining our financial discipline and a strong balance sheet.

We have a track record of maintaining prudent financial policies and a strong balance sheet. We have maintained low leverage and financial discipline when funding acquisitions such as Baúna in 2019 and Who Dat in 2023. We believe our approach provides us with the flexibility to pursue our growth strategy and the ability to be opportunistic and respond promptly as opportunities emerge in our regions of focus. We consider our balance sheet to be a competitive advantage as it provides sellers with confidence in our ability to complete transactions.

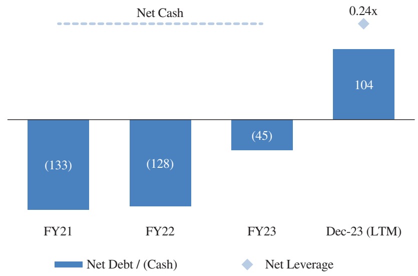
Our financial policies and financial discipline, and our low cash breakeven price of US$22.40 per boe during TY23 provide us with flexibility to remain unhedged (subject to our RBL facility obligations) and retain exposure to movements in oil and gas prices. We consider this important to maximize value for our stakeholders and generate strong free cash flow through the cycle.

We have a Board approved capital allocation framework that prioritizes safe and reliable operations and meeting capital commitments (sustaining capital expenditure, debt servicing, and other mandatory capital commitments). We expect that after meeting these commitments, we will have sufficient cash from our operations to fund growth initiatives and, where appropriate, make distributions to shareholders. In accordance with the capital allocation framework, our goal is to maintain a net leverage ratio of less than 1.0 times through the cycle.

Interest Cover Ratio – Underlying EBITDA/Net Interest Expense



Net Leverage Ratio – Net Debt/Underlying EBITDA

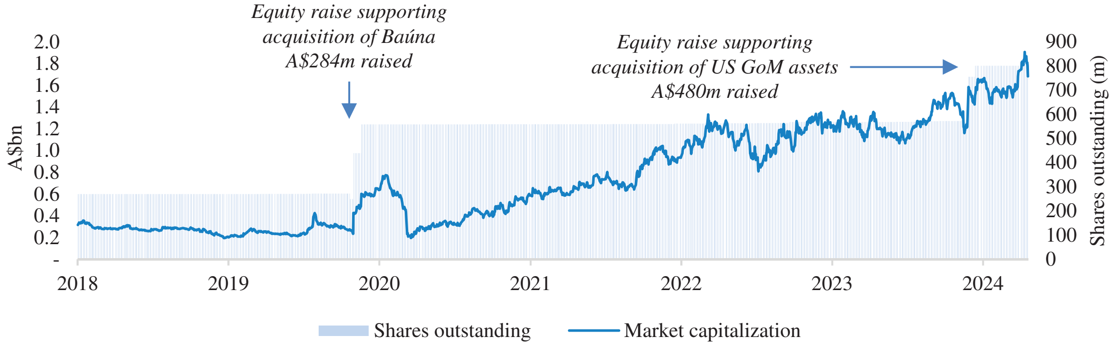


We have benefitted from strong support from capital providers. Our shareholders have supported our equity raisings to fund growth, and we have long term and supportive relationships that lend to us through our RBL facility.

Our capital providers have demonstrated their support and provided us with access to capital to fund growth, in both debt and equity markets, through the acquisition of Baúna, the refinancing of our RBL facility, and the acquisition of Who Dat.

Our shareholder register, at December 31, 2023 comprised approximately 74% institutional investors and 26% retail and other investors. The proportion of our register represented by institutional investors has increased from approximately 42% at the time that we completed the acquisition of Baúna, which we believe is the result of our transition from an explorer to a producing oil and gas company and demonstrates support from the equity market.

Equity Market Support



In respect of our debt relationships and support, in November 2021, we established the RBL facility, a reserve based syndicated loan facility, with total commitments of US$160 million. In April 2022, we increased the total facility limit to US$210 million, with the support of our existing banking relationships. In November 2023, and in anticipation of the acquisition of Who Dat, we completed a refinancing and implemented a new revolving, reserve based lending facility at reduced facility pricing, and on more flexible terms, while increasing the commitments under our facility to US$340 million. We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340 million committed under the RBL facility will become available, subject to customary conditions to draw. Deutsche Bank, Macquarie Bank, ING and Shell have participated in both of our reserve based facilities. See "Description of other financing arrangements."

We have a strong track record for conducting our operations in a safe, reliable, and environmentally responsible manner, and have ESG policies and procedures designed to achieve our carbon emissions targets.

We have a strong track record for conducting our operations in a safe, reliable, and environmentally responsible manner. We have had no recordable incidents reported over the 12 months ended December 31, 2023. We believe our safety performance is important for all of our stakeholders, and that consistent safety performance supports our long term sustainability as a business and our reputation as a corporate citizen in the markets that we operate.

We also have ESG policies and procedures in place designed to achieve our stated goals for our carbon emission performance. We have been carbon neutral[20] for Baúna since 2021 and aim to be carbon neutral for any acquired assets within five years of purchase, including our Who Dat assets. We aim to achieve net zero[21] by 2035 and have implemented a carbon management action plan designed to help us reach these targets. We have entered into several agreements to purchase externally verified emission reduction certificates, that help offset a portion of our forecast emissions and take emissions into account in our internal decision-making whenever we consider new investments. See "—Our strategy—We intend to continue to operate responsibly and sustainably in accordance with our sustainability strategy and objectives."

We have an experienced board and management team with deep industry expertise.

Our board and management team has significant experience in the international oil and gas industry. The board and management comprises experienced industry veterans that have worked in major oil and gas jurisdictions, including long term experience in Brazil and the United States of America. Our board and management team has guided our transition from an explorer to a producer, delivering the acquisition and development of Baúna and more recently the acquisition of the Who Dat assets.

Our management team have a track record of adding value through acquisitions, developing in-field and near-field opportunities, lowering unit costs of production, improving safety and reliability, delivering our projects on time and on budget, and increasing our reserves. Our team has delivered these outcomes while maintaining a strong balance sheet. Our chief executive officer and managing director, Dr. Julian Fowles has over 30 years of experience in oil and gas operations, including 17 years of working in the upstream sector across the globe. He previously held senior positions with Shell, Cairn India and Oil Search. Our chief financial officer, Ray Church, executive vice president commercial, Stephen Power and executive vice president technical, Roland Hamp, each also have more than 35 years of experience in the resources and energy sector.

We are geoscience and engineering led and focus on delivering growth through robust technical assessment and evaluation. We consider our technical expertise to be crucial to identifying and delivering value accretive growth opportunities.

Our strategy

Our strategy is to be a diversified, independent, offshore oil and gas production and exploration company with a focus on value creation, value accretive growth and prudent balance sheet management in the regions of Brazil and North America. We aim to be carbon neutral while targeting net zero by 2035.

20 Carbon neutral refers to having a balance between emitting and offsetting greenhouse gas emissions, achieved through acquiring carbon offsets in respect to our Scope 1 and 2 GHG emissions. Scope 1 emissions refer to GHG released directly from operations within Karoon's (including operational control and equity share). This includes emissions from stationary combustion (e.g. generator turbines onboard the FPSO), mobile combustion (e.g. supply vessels and fleet cars), fugitive emissions (e.g. general leaks), and process emissions (e.g. from flaring). Scope 2 emissions refers to indirect GHGs released from the energy purchased at offices and shorebases. We typically purchase carbon offsets within twelve months of the preceding calendar year.

21 Net zero refers to the reduction of Scope 1 and 2 GHG emissions as far as possible and offsetting the residual greenhouse gas emissions through investment in carbon removal or sequestration initiatives equal or greater to the residual greenhouse gas amount.

We intend to grow production volumes through acquisitions, targeting opportunities in North America and Brazil, that leverage our technical expertise and teams in these regions.

We have publicly stated our 50 for 10 growth strategy, which we intend to pursue through acquisitions and bringing into production our development assets. Our 50 for 10 strategy is focused on increasing our average daily production to achieve a minimum production rate of 50,000 boepd and sustaining that level of production for a period of no less than 10 years.

We intend to continue to evaluate acquisition opportunities, focusing primarily on producing assets offshore the United States and Brazil that would increase our production, operating cash flow and profitability. Assets in these geographies would enable us to leverage our presence in Houston and Rio de Janeiro and our technical expertise in the region, as well as potentially providing opportunities to use existing infrastructure. Our acquisition of Who Dat is consistent with our strategy. However, we may also examine acquisition opportunities in other locations and at different stages of development.

We are seeking to increase our production scale and longevity and consider that targeting producing and free cash flow generating assets is a lower risk approach that will allow us to achieve these goals over the near- to medium-term. By targeting mid-life assets we are also able to leverage our in-house experience and technical capabilities to allow us to achieve high levels of production efficiency, control costs, and realize value from maturing and under-developed assets. Consistent with our acquisition of Who Dat, we aim to achieve asset life extensions and maximize economic recovery to enable future growth.

We intend to optimize and enhance the production from our existing assets through the development of in-field and near-field growth opportunities to grow our reserves and resources.

We intend to continue to enhance production and reserves from our existing asset base by further exploiting our fields in the Santos Basin and US Gulf of Mexico. Our strategy is to identify and pursue lower risk and higher margin production growth opportunities through leveraging our expertise in well understood geological conditions and maximizing the utilization of our existing infrastructure by pursuing tie back opportunities wherever possible. We have delivered production growth at Baúna through the workover and development programs, and intend to continue optimizing production through workover programs, development drilling, and infrastructure-led exploration which, if successful, can be brought into production relatively quickly and economically.

We intend to progress the potential development of Who Dat East, Who Dat South and Who Dat West, which we believe have the potential to result in a material increase in our production and replacement of our reserves. The joint venture intends to drill an appraisal well at Who Dat East starting in late April 2024. We expect an exploration well to be drilled at Who Dat South in the second half of 2024, and subject to approval by the joint venture partners, a second exploration well to be drilled at Who Dat West, also during the second half of 2024. The Who Dat East discovery and Who Dat South and West prospects, if successful, are expected to be developed through a tie back to the existing Who Dat floating production system, which has the potential to minimize additional capital expenditure requirements, while increasing our production, free cash flow, and profitability. We also continue to examine a range of development options for the Neon discovery in the Santos Basin. During the second quarter of 2024, we approved the progression of the Neon discovery into the "concept select phase", the second stage of our project maturation process.

We will strive to maintain our safety performance.

We have a record of conducting our operations in a safe, reliable, and environmentally responsible manner, and we intend to strive to maintain these standards. The safety of our people is our highest priority and is integral to the sustainability of our business.

To foster a proactive safety culture and shared 'duty of care', we, together with our principal contractors, provide safety inductions, continuous education, and training programs for all workers. We are committed to meeting and, where practical, exceeding the requirements set by relevant laws and regulations in the areas where we operate.

Despite a material increase in exposure hours at Baúna during FY23 as a result of the Baúna workover campaign, the Patola development drilling and control well drilling at Neon, we experienced a total of four reportable safety incidents and injuries during FY23. At the end of March 2024, the Who Dat floating production system facility went through more than 4,550 days since its last reportable safety incident and more than 4,250 days since its last recordable safety incident.

Our Operating Management System reflects our expectations of safety and integrity across our operated assets. The Operating Management System, which encompasses policies, guidelines, and procedures, is regularly reviewed and updated with the aim of ensuring compliance in all applicable jurisdictions.

We intend to continue to operate responsibly and sustainably in accordance with our sustainability strategy and objectives.

We recognize our responsibility to contribute to the communities and environments in which we operate, and the role that industry must play in the reduction of global carbon emissions. We maintain a robust ESG reporting framework and have a sustainability strategy that we intend to continue to execute.

A key aspect of our sustainability strategy is our carbon management action plan. We have been carbon neutral for Baúna since 2021 and aim to be carbon neutral for any acquired assets within five years of purchase, including our Who Dat assets. We aim to achieve net zero by 2035 and have implemented a carbon management action plan designed to help us reach these targets. The first step in our carbon management action plan is to eliminate or reduce emissions. An example of this was the installation of a marine vessel mooring buoy at Baúna which has reduced emissions. The second step with our carbon management action plan is to purchase carbon offsets that fully offset our scope 1 and 2 emissions. In 2022, we entered into agreements to purchase verified carbon units from Shell and Climate Impact Partners and during the second half of 2023, we entered into an agreement to purchase verified carbon units from the Hiwi REDD+ forest conservation project in the Amazon region, operated by Carbonext. The third step with our carbon management action plan is to invest in carbon sequestration projects, with a focus on nature-based solution projects in the country of our operations. We have been closely engaged with several reputable nature-based solution developers in Brazil, and we intend to continue to assess these opportunities as necessary to achieve our target of net zero (Scope 1 & 2 emissions) by 2035, and see value in investing in high quality offset producers, rather than buying offsets, over the longer term.

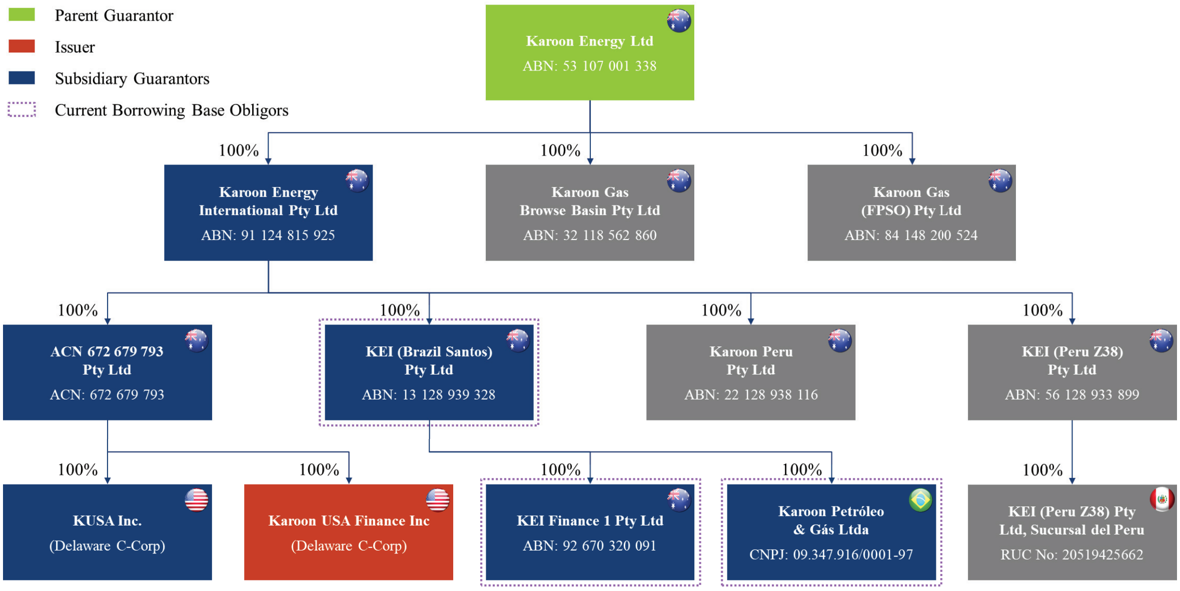
We intend to maintain our financial discipline and our strong balance sheet as we pursue our growth strategy.

We plan to maintain prudent financial policies and a strong balance sheet with low leverage designed to enable support from our capital providers, with the objective of being able to access capital from both debt and equity markets on reasonable market terms. We believe this approach will assist in supporting the delivery of our growth strategy.

We plan to fund growth through a combination of operating cash flow, debt, and equity where needed and appropriate. We have historically funded our acquisitions in what we believe to be a prudent manner as we did for Baúna where we funded the acquisition through cash and an equity raise, and Who Dat which we funded through cash, debt and an equity raise while maintaining low leverage. We intend to continue our financial discipline and maintaining what we believe to be balance sheet strength, and while also focusing on maintaining liquidity levels, reasonable leverage, while satisfying with our publicly stated capital allocation framework.

Corporate structure

The following chart shows our corporate structure.



Note: We expect KUSA Inc. to become a "Borrowing Base Obligor" in connection with our RBL facility by June 30, 2024.

Corporate information

The registered office of the Issuer is 251 Little Falls Drive, Wilmington, Delaware, 19808, United States of America. The registered office of our Parent Guarantor is at Level 3, 6 Riverside Quay, Southbank Victoria, 3006, Australia. Our telephone number is +61 3 9616 7500. Our website is located at www.karoonenergy.com.au. The information on our website or that we have filed with the ASX is not part of, or incorporated by reference in, this offering memorandum.

Recent developments

Since our most recent reporting date at December 31, 2023, there have been certain recent developments in our business which have had an impact our results of operation, and financial performance.

Shareholder Actions

On April 30, 2024, Sandon Capital Pty Ltd ("Sandon Capital"), which owns approximately 0.6% of the voting shares in the Parent Guarantor, filed a notice with the ASX indicating that it intended to associate with Samuel Terry Asset Management Pty Ltd as trustee for Samuel Terry Absolute Return Fund (ABN 25 726 469 409) ("Samuel Terry"), which owns approximately 5.0% of the voting shares in the Parent Guarantor, in order to influence the outcome of the Parent Guarantor's annual general meeting scheduled for May 23, 2024. On May 1, 2024, the Parent Guarantor received a letter from Sandon Capital confirming their intention to vote against the reelection of Mr. Peter Turnbull as a director of the Parent Guarantor, the grant of performance rights to Dr. Julian Fowles, an increase in the aggregate fee pool for non-executive directors, an increase in the share placement capacity of the Parent Guarantor and the adoption of the Parent Guarantor's remuneration report. The letter indicates that Sandon Capital will actively seek to persuade other shareholders to vote in the same manner. Samuel Terry has publicly stated that it believes the Parent Guarantor should be prioritizing dividends and share buybacks rather than acquisitions and development.

March 2024 quarter production update

Our production for the quarter ended March 31, 2024 was 3.11 MMboe on an NWI basis and 2.94 MMboe on a NRI basis. Sales volumes were 2.74 MMboe on an NRI basis.

Production from Baúna was 2.16 MMboe on an NRI basis, 15% lower than in the prior quarter. Production was impacted by ongoing FPSO reliability issues, the shut-in of the SPS-88 well for the full period and natural decline.

Production from Who Dat was 0.78 MMboe on an NRI basis. Production was lower than forecast due to delays in bringing new wells online, lower well productivity than anticipated and bottlenecks in the subsea production system. In addition, production from high-rate gas wells was curtailed to prioritize oil production in the current low gas price environment. The figure for Who Dat (and therefore our total production) is pending a final reconciliation and may change slightly as a result.

Offtake and marketing agreements

Since the acquisition of our interest in the Who Dat assets, we commenced discussions with parties to diversify our offtake and marketing agreements for our production from Who Dat. We recently entered into offtake agreements with subsidiaries of the BP group for crude and gas, and Williams for natural gas liquids, from Who Dat. We expect to finalize further offtake and marketing agreements through 2024, in order to further optimize netback opportunities. For additional information on our offtake and marketing agreements see "Business—Our production and exploration assets" and "Management's discussion and analysis of financial condition and results of operations—Key income statement line items—Revenue."

Who Dat nominated a "Borrowing Base Asset"

We have commenced discussions with respect to the re-determination process for the borrowing base amount under our RBL facility to include Who Dat as a "Borrowing Base Asset" by June 30, 2024. Following the inclusion of Who Dat, we expect the borrowing base amount will exceed the borrowing base limit, resulting in the borrowing capacity under RBL facility increasing from US$274 million as of December 31, 2023 to US$340 million.

Hedging

We have implemented hedging arrangements with respect to a portion of our production to reduce our exposure to movements in oil prices. We hedged 4.26 million barrels of Baúna oil production over the period from March 2024 to December 2025. Hedging has been implemented with the use of a collar and options to mitigate upfront costs of hedging and the potential for forward delivery risk. For additional information on our hedging strategy see "Management's discussion and analysis of financial condition and results of operations—Key factors affecting our results—Oil and gas prices."

Leadership

On April 19, 2024, we appointed Ms. Melissa Holzberger and Ms. Joanne Palmer as independent non-executive directors to our board. See "Management—Board of directors." Also on April 19, 2024, we proposed the issue of 121,594 short-term incentive and 506,475 long-term incentive performance rights to our chief executive officer, Dr. Julian Fowles for shareholder approval. For additional information on our compensation structure see "Management—Compensation."

Risk factors

Investing in the Notes offered by this offering memorandum involves significant risks. You should carefully consider all the information in this offering memorandum prior to investing in the Notes. There are numerous risks related to our business and the Notes that are described under "Risk factors" and elsewhere in this offering memorandum.

THE OFFERING

Notes Being Offered	US$350,000,000 10.500% Second-Priority Senior Secured Notes due 2029 (the "Notes").
Issuer	Karoon USA Finance Inc
Parent Guarantor	Karoon Energy Limited
Subsidiary Guarantors	Karoon Energy International Pty Ltd, KEI (Brazil Santos) Pty Ltd, KEI Finance 1 Pty Ltd, ACN 672 679 793 Pty. Ltd., Karoon Petroleo & Gas Ltda and KUSA Inc. (together with the Parent Guarantor, the "Guarantors").
Issue Date	May 14, 2024.
Principal Amount	US$350,000,000 aggregate principal amount.
Maturity Date	May 14, 2029.
Interest Rate	The Notes will bear interest at the rate of 10.500% per year from May 14, 2024, based upon a 360-day year consisting of twelve 30-day months.
Interest Payment Dates	The first interest payment on the Notes will be made on November 14, 2024. Thereafter, interest on the Notes will be payable semi-annually in arrears on May 14 and November 14 of each year.
Guarantee	The Guarantors and each of the Parent Guarantor's future direct or indirect wholly-owned Restricted Subsidiaries (as defined under "Description of the Notes—Certain Definitions") that (i) incurs or guarantees indebtedness under the RBL facility, or (ii) incurs or guarantees other credit facilities or other indebtedness of the Parent Guarantor, the Issuer or any other Guarantor in excess of US$25 million will fully and unconditionally guarantee the obligations of the Issuer under the Notes on a joint and several basis, including the payment of the principal of, premium, if any, and interest on the Notes (the "Guarantees"). The Guarantees will be secured on a second-priority senior secured basis in the Collateral as described below under "—Security."
Ranking	The Notes and the Guarantees will be the Issuer's and the Guarantors' senior secured obligations and will: • rank equally in right of payment with the Issuer's and Guarantors' existing and future senior obligations; • rank senior in right of payment to any of the Issuer's and Guarantors' obligations that are subordinated to the Notes and the Guarantees;

- be effectively senior in right of payment to all existing and future obligations of the Issuer and the Guarantors that are unsecured or secured by the Collateral on a junior basis to the Notes and Guarantees, in each case, to the extent of the value of the Collateral that is available to satisfy the obligations under the Notes and Guarantees;

- be effectively *pari passu* with any of the Issuer's and Guarantors' existing and future obligations that are secured by the Collateral on a second-priority basis;

- be effectively junior to any of the Issuer's and Guarantors' existing and future obligations of the Issuer and the Guarantors that are secured by the Collateral on a first- or senior-priority basis to the Notes and Guarantees, including indebtedness under the RBL facility and associated hedging, to the extent of the value of the Collateral; and

- be structurally subordinated to all indebtedness and other liabilities of each subsidiary of the Issuer or the Guarantors that is not a guarantor of the Notes.

See "Description of the Notes—Ranking."

As of December 31, 2023 on an as adjusted basis after giving effect to (i) the offering of Notes contemplated hereby, (ii) the repayment of our prior reserve-based, non-recourse, syndicated loan facility (which was repaid and canceled after December 31, 2023) and (iii) the repayment of the outstanding amount of the RBL facility as described under "Use of proceeds", the Notes will constitute our only substantial financial indebtedness. Subject to customary conditions to draw, US$246.0 million would be available immediately to be redrawn under the RBL facility, which indebtedness would be first-priority secured indebtedness and therefore effectively senior to the Notes. We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340 million committed under the RBL facility will become available, subject to customary conditions to draw.

The subsidiaries of the Parent Guarantor that will not guarantee the Notes on issuance have substantially no outstanding indebtedness, assets, liabilities, revenues or profits.

Security..	The Notes and Guarantees will be secured on a second-priority security basis by the security interests in the Collateral (which generally includes substantially all of the existing and future assets of the Issuer and the Guarantors) subject to permitted liens and certain customary exclusions and materiality thresholds as more particularly described herein, which assets will also secure the RBL facility and associated hedging on a first-priority basis and other indebtedness that is permitted under the indenture to be secured on a senior priority basis to the Notes and Guarantees. Such Collateral comprises (i) the equity interests in KEI (Brazil Santos) Pty Ltd, KEI Finance 1 Pty Ltd and Karoon Petroleo E Gas Ltda (together, the "Borrowing Base Obligors"), the material borrowing base assets of the Borrowing Base Obligors (including petroleum assets, bank accounts, material contracts, insurance policies, hedging policies and intragroup loans) and, where customary in the applicable jurisdiction, an all assets general security deed or equivalent composite security over each Borrowing Base Obligor's assets and (ii) the shares or other equity interests in the Issuer, Karoon Energy International Pty Ltd, A.C.N. 672 679 793 Pty. Ltd. and KUSA Inc. (together with the Parent Guarantor, the "Corporate Guarantors") and, where customary in the applicable jurisdiction, an all assets general security deed or equivalent composite security over the Corporate Guarantors' assets. Following the completion of the offering, we expect KUSA Inc. will become a Borrowing Base Obligor and grant holders of the Notes security over its interests in the Who Dat assets, subject to the approval of the lenders under the RBL facility. Collateral comprising the directly held equity interests in, and assets of, Borrowing Base Obligors constitutes "Borrowing Base Priority Collateral." The Collateral securing the Notes will exclude: • assets (including, but not limited to, contracts, leases, authorizations or other third party arrangements) that are subject to a restriction on the creation of security under any contract, lease, authorization or other third party arrangement or applicable law or regulation; provided that we will use commercially reasonable efforts to obtain consent to such assets being included in the Collateral where they are material to Karoon Energy; • certain bank accounts (including certain payroll and other employee accounts), tax accounts, contractual escrow accounts and fiduciary or trust accounts; • with respect to the Issuer or any U.S. Guarantor or assets in the U.S., vehicles and other assets subject to certificate of title statutes (except where such security is perfected by an all assets Uniform Commercial Code financing statement, or equivalent), certain "intent to use" trademark applications, fee-owned real property which is not a material asset, any leasehold interests in real property and any margin stock; and

- in the case of Collateral other than Borrowing Base Priority Collateral, assets other than the equity interests in Guarantors (other than the Company) and wholly-owned material subsidiaries, material intra-group receivables and material operating bank accounts, provided that, where customary, a floating general security (or equivalent) will be granted over the other assets of the applicable Guarantor.

For more information on the security granted see "Description of the Notes—Security." The security interests in the assets securing the Notes may be released under certain circumstances without your consent or the consent of the trustee.

See "Risk factors—Risks related to the Notes and Security" and "Description of the Notes—Security—Release of Collateral."

Intercreditor Agreements................ The security in the Collateral is held by the Common Security Agents (as defined below) for the benefit of the holders of all applicable secured indebtedness that is or becomes subject to the intercreditor agreements, including the RBL facility and the Notes. See "—Common Security Agent" below. References herein to ranking, priority or subordination of liens with respect to the RBL facility, the Note or other secured indebtedness are to be construed as including the ranking, priority or subordination of secured indebtedness with respect to the liens held in the Collateral by the Common Security Agents for the benefit of the secured creditors.

The security granted in the Collateral to secure the Notes on a second-priority basis also secures, on a first-priority basis, indebtedness under the RBL facility and associated hedging. In addition, the indenture will permit us to secure additional indebtedness with liens on the Collateral under certain circumstances. The security over the Collateral will rank and secure the RBL facility, the Notes and such additional secured indebtedness in the following order of priority:

- in the case of Borrowing Base Priority Collateral, (x) first, the RBL facility and associated hedging, (y) next, any senior secured indebtedness that is secured by the Borrowing Base Priority Collateral on a senior-priority basis to the Notes but on a junior-priority basis to the RBL facility ("senior-priority obligations", and the RBL facility and associated hedging and senior-priority obligations, collectively, the "first-priority lien obligations" or "first-priority indebtedness") and (z) next the Notes and, subject to the entry into of a Second Lien Intercreditor Agreement (referred to below) any other indebtedness secured by the Borrowing Base Collateral on a *pari passu* basis with the Notes (collectively, the "second-priority obligations" or "second priority indebtedness"); and

- in the case of other Collateral, (x) first, the first-priority lien obligations and (y) second, the Notes and other second-priority lien obligations.

Intercreditor agreements, in each case, to be joined or agreed to, as applicable, on the Issue Date (or, in the case of the Second Lien Intercreditor Agreement referred to below, on or prior to the incurrence of any other series of second lien obligations) by (or on behalf of) the Trustee for the Notes, will establish (x) the subordination of the liens on the Collateral securing the Notes and the Guarantees and the liens securing other second lien obligations to the liens on the Collateral securing first-priority lien obligations, comprising the RBL facility and any future first-priority lien obligations (the "Senior Lien Intercreditor Agreement"), and (y) the equal priority of the liens on the Collateral securing the Notes and the Guarantees to any liens on the Collateral securing any future second-priority obligations (the "Second Lien Intercreditor Agreement").

See "Description of the Notes—Security—Senior Lien Intercreditor Agreement" and "Description of the Notes—Security—Second Lien Pari Passu Intercreditor Agreement."

Optional Redemption .... The Notes will be redeemable at our option, in whole or in part, beginning on May 14, 2026, at the redemption prices set forth in this offering memorandum, together with accrued and unpaid interest, if any, to, but excluding, the date of redemption.

At any time prior to May 14, 2026, we may also redeem any of the Notes at a price equal to 100% of the principal amount of the Notes redeemed plus a "make-whole premium," together with accrued and unpaid interest, if any, to, but excluding, the date of redemption.

At any time prior to May 14, 2026, we may redeem up to 40% of the original principal amount of the Notes with an amount equal to the net cash proceeds of certain equity offerings at a redemption price of 110.500% of the aggregate principal amount of the Notes, together with accrued and unpaid interest, if any, to, but excluding, the date of redemption.

Prior to May 14, 2026, we may redeem during each 12-month period commencing with the Issue Date up to 10% of the original principal amount of the Notes at its option, at a redemption price equal to 103% of the principal amount of the Notes redeemed, plus accrued and unpaid interest, if any, to, but excluding, the date of redemption.

	If holders of not less than 90% in aggregate principal amount of the outstanding Notes validly tender and do not withdraw such Notes in any redemption and the Issuer, or any third party making such an offer in lieu of the Issuer, purchases all of the Notes validly tendered and not withdrawn by such holders, the Issuer or such third party will have the right to redeem all Notes that remain outstanding following such purchase at a price in cash equal to the price offered to each other holder in such tender offer (which may be less than par and shall exclude any early tender premium or similar premium and any accrued and unpaid interest paid to any holder in such tender offer payment) plus, to the extent not included in the tender offer payment, accrued and unpaid interest, if any, thereon to but excluding the redemption date or purchase date, subject to the right of holders of record of Notes on the relevant record date to receive interest due on the relevant interest payment date falling on or prior to the redemption date or purchase date. See "Description of the Notes—Optional redemption."
Additional Amounts	All payments made by us under or with respect to the Notes or by any of the Guarantors with respect to any Guarantee will be made without withholding or deduction for taxes unless required by law. If the Issuer or any Guarantor is required by law to withhold or deduct for taxes imposed by any relevant taxing jurisdiction with respect to a payment to the holders of Notes, the Issuer or such Guarantor, as applicable, will pay the additional amounts necessary so that the net amount received by the holders of Notes after the withholding or deduction is equal to the amount that they would have received in the absence of the withholding or deduction, subject to certain exceptions. See "Description of the Notes—Additional amounts."
Optional Redemption for Tax Reasons	In the event of certain developments affecting taxation, the Issuer may redeem the Notes in whole, but not in part, at any time upon giving prior notice, at a redemption price of 100% of the principal amount, plus accrued and unpaid interest, if any, and additional amounts, if any, to the date of redemption. See "Description of the Notes—Tax redemption."
Change of Control Offer to Repurchase......................................	If a Change of Control, as defined under "Description of the Notes—Change of Control," occurs with respect to the Notes, we will be required to offer to repurchase the Notes at a repurchase price equal to 101% of the principal amount, plus accrued and unpaid interest, if any, to, but excluding, the repurchase date. See "Description of the Notes—Change of Control."

Asset Sale Offer to Repurchase	If we sell certain assets, under certain circumstances, we will be required to offer to repurchase the Notes at a repurchase price equal to 100% of the principal amount, plus accrued and unpaid interest, if any, to, but excluding, the repurchase date. See "Description of the Notes—Certain covenants—Asset sales."
Certain Covenants	The indenture will limit, among other things, the ability of the Issuer, the Parent Guarantor and the Restricted Subsidiaries to: • incur or guarantee additional indebtedness; • pay dividends or distributions on, or redeem or repurchase, capital stock and make other restricted payments; • make certain investments; • consummate certain asset sales; • engage in certain transactions with affiliates; • agree to any restrictions on the ability of the Restricted Subsidiaries to make payments to the Parent Guarantor and Issuer; • grant or assume liens on certain assets; and • consolidate, merge or transfer all or substantially all of the Parent Guarantor's or the Issuer's assets. These covenants are subject to important exceptions and qualifications. In addition, our subsidiaries that are designated as unrestricted subsidiaries by the board of directors of the Parent Guarantor and subsidiaries of an unrestricted subsidiary (together our "Unrestricted Subsidiaries") will not be subject to these covenants. For more details regarding these exceptions and qualifications, see "Description of the Notes—Certain covenants." In addition, certain of the covenants will be suspended if any two of Moody's Investors Service, Inc., Fitch Ratings, Inc. and Standard & Poor's Ratings Services assigns the Notes an investment grade rating in the future and certain other conditions are met. See "Description of the Notes—Certain covenants." In the event that the Parent Guarantor and the Restricted Subsidiaries are not subject to such covenants for any period of time as a result of the preceding sentence and, on any subsequent date, either of such rating agencies withdraws or downgrades the ratings assigned to the Notes, then the Parent Guarantor and the Restricted Subsidiaries will thereafter again be subject to such covenants.

No Registration Rights....................	We will not be required to, nor do we intend to, register the Notes and Guarantees for resale under the Securities Act or the securities laws of any other jurisdiction or to offer to exchange the Notes for registered notes under the Securities Act or the securities laws of any other jurisdiction.
Use of Proceeds	We estimate the net proceeds from the offering of the Notes will be approximately US$343,875,000 after deducting the discounts to the Initial Purchasers but before deducting the estimated offering expenses payable by us. We intend to use a portion of the net proceeds of the offering to repay the outstanding amount of US$246.0 million under our RBL facility, which will remain available to be redrawn, and use the remainder of the net proceeds for general corporate purposes, which may include acquisitions. See "Use of proceeds" and "Description of other financing arrangements."
Transfer Restrictions	The Notes and the Guarantees have not been registered under the Securities Act or any state securities laws and are subject to restrictions on transfers. The Notes may not be offered or sold, except pursuant to an exception from or in a transaction not subject to the registration requirements of the Securities Act. See "Transfer restrictions."
Trustee	GLAS Trust Company LLC.
Common Security Agent	Citibank, N.A. as offshore common security agent and Banco Citibank S.A. as onshore common security agent are the common collateral agents under the Senior Lien Intercreditor Documents (as defined under "Description of the Notes—Certain Definitions") (the "Common Security Agents") and hold security for all secured parties under the Senior Lien Intercreditor Documents.
Paying Agent, Transfer Agent and Note Registrar (collectively, the "Agents")	GLAS Trust Company LLC.
Governing law	The Notes, the Guarantees and the indenture will be governed by New York law. The security documents are governed by English, Australian, Brazilian or New York law, as applicable.
Risk factors....................................	Prospective purchasers of the Notes should consider carefully all of the information set forth in this offering memorandum and, in particular, the information set forth under "Risk factors" before making an investment in the Notes.

Absence of Public Market for the Notes and SGX-ST Listing	The Notes are a new issue of securities, and there is currently no established trading market for the Notes. Accordingly, there can be no assurance as to the development or liquidity of any market for the Notes. See "Risk Factors—Risks Related to the Notes and Security—Your ability to transfer the Notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop, or if developed be maintained, for the Notes." We intend to apply for the listing and quotation of the Notes on the SGX-ST. We cannot assure you that this application will be accepted or if accepted that, once listed, the Notes will remain listed. The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions or reports contained in this offering memorandum. Admission of the Notes to the Official List of the SGX-ST, and the listing and quotation of the Notes on the Official List of the SGX-ST, are not to be taken as an indication of the merits of the Issuer, the Guarantors, our subsidiaries, our associated companies, the Notes or the Guarantees. The Notes will be traded on the SGX-ST in a minimum board lot size of S$200,000 (or its equivalent in foreign currencies) for as long as any of the Notes are listed on the SGX-ST and the rules of the SGX-ST so require. In addition, for so long as the Notes are listed on the SGX-ST and the rules of the SGX-ST so require, the Issuer will appoint and maintain a paying agent in Singapore, where the Notes may be presented or surrendered for payment or redemption, in the event that the Global Note is exchanged for Certificated Notes. In addition, in the event that the Global Note is exchanged for Certificated Notes, an announcement of such exchange shall be made by or on behalf of the Issuer through the SGX-ST and such announcement will include all material information with respect to the delivery of such Certificated Notes, including details of the paying agent in Singapore.

SUMMARY HISTORICAL CONSOLIDATED FINANCIAL AND OTHER DATA

The income statement and cash flow information for the financial years ended June 30, 2021 ("FY21"), 2022 ("FY22") and 2023 ("FY23"), the half year ended December 31, 2022 ("HY23") and the transitional financial year ended December 31, 2023 ("TY23") and the balance sheet information as of June 30, 2021, 2022 and 2023 and December 31, 2022 and 2023 have been extracted from our audited consolidated financial statements as of and for the financial years ended June 30, 2022 and 2023 and the transitional financial year ended December 31, 2023 and our unaudited condensed consolidated financial statements for the half-year ended December 31, 2022, in each case included in this offering memorandum, and reflect the consolidated results of operations, cash flows and assets and liabilities of Karoon Energy Limited for such periods.

Our financial statements have been prepared in accordance with the recognition and measurement principles of AAS and IFRS, which differ from US GAAP. You should read the selected consolidated and combined financial data set forth below together with the information in "Financial information presentation," "Management's discussion and analysis of financial condition and results of operations" and "Risk factors," and the Karoon Energy financial statements included elsewhere in this offering memorandum.

Consolidated Statement of Profit or Loss Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Revenue	170.8	385.1	566.5	299.4	412.9
Cost of sales	(111.4)	(191.7)	(283.2)	(148.3)	(164.5)
Gross profit	**59.4**	**193.4**	**283.3**	**151.1**	**248.4**
Other income	0.3	0.8	5.7	1.1	2.6
Business development and other project costs(1)	(17.6)	(3.4)	–	(1.5)	–
Exploration and evaluation expenditure expensed(1)	(3.4)	(3.2)	–	(1.7)	–
Finance costs	(14.4)	(22.7)	(25.4)	(11.7)	(15.9)
Net foreign currency gains/(losses)	(17.1)	6.2	(0.8)	0.3	(8.1)
Other expenses(1)	(28.5)	(33.8)	(41.4)	(20.8)	(41.4)
Change in fair value of contingent consideration	(6.6)	(227.1)	(5.2)	(0.4)	(3.5)
Profit/(loss) before income tax	**(27.9)**	**(89.8)**	**216.2**	**116.4**	**182.1**
Income tax (expense)/benefit	32.3	25.4	(53.2)	(38.8)	(59.6)
Profit/(loss) for the financial period attributable to equity holders of the Company	**4.4**	**(64.4)**	**163.0**	**77.6**	**122.5**

Note:

(1) Prior to TY23, we reported our business development and other project costs and our exploration and evaluation expenditure expensed as separate items on our income statement. In TY23, we included these costs in our other expenses line item, and we reclassified our other expenses for FY23 so that it is presented on the same basis.

Consolidated Statement of Financial Position Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Current assets					
Cash and cash equivalents	133.2	157.7	74.8	163.2	170.4
Receivables	34.2	56.4	73.1	79.3	56.4
Inventories	11.0	19.4	8.7	14.8	18.7
Security deposits	0.2	0.3	–	–	–
Other financial assets	–	–	3.0	–	0.2
Other assets	5.3	11.8	7.6	7.3	6.6
Total current assets	**183.8**	**245.6**	**167.2**	**264.6**	**252.3**
Non-current assets					
Deferred tax assets	36.5	123.0	124.7	125.3	95.2
Inventories	6.5	5.8	8.3	4.5	10.8
Oil and gas assets	736.4	733.0	798.7	813.2	1,391.0
Property, plant and equipment	8.3	13.3	2.7	2.9	3.1
Intangible assets	0.1	–	0.1	–	0.3
Exploration and evaluation assets	40.9	40.9	85.7	41.3	175.3
Security deposits	1.4	1.3	–	2.4	–
Other financial assets	–	–	–	1.4	–
Other assets	–	1.3	3.0	1.2	4.5
Total non-current assets	**830.1**	**918.6**	**1,023.2**	**992.2**	**1,680.2**
Total assets	**1,014.0**	**1,164.2**	**1,190.4**	**1,256.8**	**1,932.5**
Current liabilities					
Trade and other payables	76.2	68.3	57.2	70.2	68.3
Borrowings	–	–	–	–	0.1
Current tax liabilities	8.3	9.6	5.6	44.8	16.8
Other financial liabilities	–	125.4	86.0	96.1	86.0
Lease liabilities	45.4	43.7	47.2	45.2	48.7
Provisions	0.5	0.4	0.2	0.2	0.2
Total current liabilities	**130.3**	**247.4**	**196.2**	**256.5**	**220.1**
Non-current liabilities					
Trade and other payables	4.3	6.8	5.8	5.6	7.2
Borrowings	–	27.1	28.1	27.6	264.4
Other financial liabilities	71.2	222.0	133.0	214.1	136.5
Deferred tax liabilities	1.8	–	–	–	–
Lease liabilities	267.4	245.2	200.4	222.0	175.7
Provisions	158.8	139.5	153.3	151.9	214.6
Total non-current liabilities	**503.4**	**640.6**	**520.6**	**621.2**	**798.4**
Total liabilities	**633.7**	**888.0**	**716.8**	**877.7**	**1,018.5**
Net assets	**380.3**	**276.2**	**473.6**	**379.1**	**914.0**
Equity					
Contributed equity	905.1	907.5	907.5	907.5	1,210.8
Accumulated losses	(414.4)	(478.8)	(315.8)	(401.2)	(193.3)
Reserves	(110.5)	(152.5)	(118.1)	(127.2)	(103.5)
Total equity	**380.3**	**276.2**	**473.6**	**379.1**	**914.0**

Consolidated Statement of Cash Flows Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Cash flows from operating activities					
Receipts from customers	137.0	362.9	552.9	276.7	443.3
Payments to suppliers and employees	(56.5)	(116.5)	(135.2)	(66.8)	(106.2)
Net refunds for Peruvian VAT	4.2	–	–	–	–
Payments for exploration and evaluation expenditure expensed	(15.2)	(3.5)	(4.0)	(1.3)	(3.3)
Payments for Baúna transition expenditure	(15.9)	–	–	–	–
Payments for legal settlement	–	(9.6)	–	–	–
Payments for cash flow hedges	–	(20.8)	(13.4)	(12.7)	(2.7)
Interest received	0.3	–	4.2	1.4	1.0
Borrowing and other costs of finance paid	(13.2)	(18.9)	(19.8)	(9.3)	(9.2)
Income taxes paid	(10.8)	(39.4)	(78.8)	(20.9)	(19.5)
Net cash flows from operating activities	**29.8**	**154.2**	**305.9**	**167.1**	**303.4**
Cash flows from investing activities					
Purchase of plant and equipment and computer software	(4.7)	(5.1)	(2.5)	(2.3)	(0.9)
Acquisition of oil and gas assets	(150.0)	(43.6)	(84.5)	–	(636.8)
Acquisition of exploration and evaluation assets	–	–	–	–	(83.0)
Interest received on deposit	–	–	–	–	0.1
Payments for oil and gas assets	(16.0)	(59.6)	(222.5)	(137.1)	(4.2)
Borrowing costs paid for qualifying assets	(0.2)	(5.8)	(2.7)	(1.7)	–
Payments for exploration and evaluation expenditure capitalized	(1.9)	–	(43.1)	(0.5)	(3.3)
Payment for security deposits	3.6	(0.3)	(0.9)	(0.8)	–
Proceeds from disposal of non-current assets	0.0	1.4	–	–	–
Net cash flows used in investing activities	**(169.2)**	**(113.0)**	**(356.2)**	**(142.4)**	**(728.1)**
Cash flows from financing activities					
Principal elements of lease payments	(23.4)	(44.6)	(34.1)	(19.7)	(19.2)
Proceeds from issue of ordinary shares	–	2.4	–	–	312.3
Payment of equity raising costs	–	–	–	–	(8.8)
Proceeds from borrowings	–	30.0	–	–	274.0
Repayment of borrowings	–	–	–	–	(29.9)
Debt facility costs	–	(3.3)	(0.1)	–	(8.6)
Net cash flows (used in)/from financing activities	**(23.4)**	**(15.5)**	**(34.2)**	**(19.7)**	**519.8**
Net increase/(decrease) in cash and cash equivalents	(162.8)	25.7	(84.5)	5.0	95.1
Cash and cash equivalents at beginning of the period	296.4	133.3	157.7	157.7	74.8
Effect of exchange rate changes on the balance of cash and cash equivalents held in foreign currencies	(0.4)	(1.3)	1.6	0.5	0.5
Cash and cash equivalents at end of the period	**133.2**	**157.7**	**74.8**	**163.2**	**170.4**

Summary unaudited pro forma combined financial information

	Pro forma combined for the year ended December 31, 2023
	(US$ million)
Revenue	827.4
Cost of sales	(403.0)
Gross profit	**424.3**
Other income	7.2
Finance costs	(55.6)
Net foreign currency loss	(9.2)
Other expenses	(58.8)
Change in fair value of contingent consideration	(8.3)
Profit before income tax	**299.6**
Income tax expense	(78.6)
Profit for the financial period attributable to equity holders of the Company	**221.0**

This information should be read in conjunction with "Unaudited pro forma combined financial information" and "Selected unaudited pro forma combined financial information."

Summary Reserves and Resources Data

The following table sets forth our 1P, 2P, and 3P petroleum reserves and our 2C contingent resources as of December 31, 2023. We engage independent experts as required to assist with the integrity of our reserves and contingent resources estimates. The reserves and contingent resources estimates included in the table below are our own estimates. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's independent reserves report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material. For more information about our estimates, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

	As of December 31, 2023			
	1P	2P	3P	2C
	(MMboe)			
Brazil				
Baúna[(1)]	37.1	46.5	55.8	10.9
Neon[(2)]	–	–	–	60.1
Goia[(3)]	–	–	–	27.0
Gulf of Mexico				
Who Dat[(4)]	20.9	31.0	43.9	–
Who Dat East[(5)]	–	–	–	5.4
Total	**58.0**	**77.5**	**99.7**	**103.4**

Notes:

(1) Includes reserves and contingent resources from the Baúna, Piracaba and Patola oil fields presented on a NWI basis. The contingent resources figure reflects the amount of contingent resources we estimate would be recoverable following a potential FPSO life extension.

(2) These contingent resources are assessed within the development unclarified subclass and have not been subject to a commerciality determination. We allocate a contingent resource to this subclass when "project activities are under evaluation and where justification as a commercial development is unknown based on available information." While we report the recoverable resource for the whole field in this contingent resource figure, any finalized development plan may not recover all of these resources. Presented on a NWI basis.

(3) Presented on a NWI basis.

(4) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

(5) Includes our share of contingent resources in the Who Dat East oil and gas field presented on a NRI basis.

The following table sets forth PV-10 estimates of our 1P, 2P and 3P petroleum reserves as prepared by our independent experts, AGR and NSAI. See "Cautionary note regarding PV-10 values" for more information about how these PV-10s were calculated. The reserves estimates used in these PV-10 calculations are the estimates of our independent experts, which are different from our own reserves estimates.

	1P PV-10	2P PV-10	3P PV-10
		(US$ million)	
Brazil			
Baúna[(1)]	884.9	1,298.2	1,754.3
Gulf of Mexico			
Who Dat[(2)]	514.1	776.8	1,094.8
Total	**1,399.0**	**2,075.0**	**2,849.1**

Notes:

(1) Presented on a NWI basis.

(2) Presented on a NRI basis and includes the Who Dat and Dome Patrol oil and gas fields.

Summary Production and Operating Data

The following table summarizes our historical production and sales data for FY21, FY22, FY23, HY23, TY23 and pro forma production and sales data on a net revenue interest basis for FY23 and TY23 as if we had acquired our share in the Who Dat assets on July 1, 2022.

		Historical					Pro forma[2]	
		For the twelve months ended June 30,			For the six months ended December 31,		For the twelve months ended June 30,	For the six months ended December 31,
		2021	2022	2023	2022	2023[1]	2023	2023
Production	MMboe	3.14	4.64	7.04	3.37	5.47	9.78	6.83
Sales volumes	MMboe	2.90	4.54	7.06	3.41	5.07	9.76	6.40
Weighted average realized price (net of selling expense)	US$/boe	59.00	84.74	80.20	87.86	81.51	75.09	77.11

Notes:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

(2) Includes our share in the Who Dat assets on a NRI basis as if we had acquired our share in the Who Dat assets on July 1, 2022. Historical Who Dat figures have been supplied by LLOG.

Investing in the Notes offered by this offering memorandum involves risk. You should consider carefully the risks described below before you decide to purchase the Notes. The risks described below are not an exhaustive list of the risks facing us or that may develop in the future. There may be additional risks not described below, not presently known to us, or that we currently consider to be immaterial that could turn out to be material in the future. If any of the following risks actually occurs, our business, financial position and results of operations are likely to suffer. In this case, the trading price of the Notes could decline, and you may lose all or part of your investment.

Risks relating to our industry and operations

Significant declines in oil and gas prices may materially affect our financial condition and results of operations, cash flows, access to the capital markets and available borrowings under our RBL facility.

Our business generates substantially all of its revenue by producing and selling oil and, to a lesser extent, natural gas. We sell all of our oil production from Baúna under a marketing arrangement with Shell Western Supply and Trading Limited, or SWST, which is a member of the Royal Dutch Shell Plc group. We sell our share of crude oil from Who Dat to BP Products North America Inc., a member of the BP Plc group, under a month-to-month evergreen crude oil purchase agreement. We sell our share of natural gas from Who Dat on a six-month seasonal contract basis to BP Energy Company, also a member of the BP Plc group, under a gas purchase contract, and we sell our share of natural gas liquids under a life-of-asset sales agreement at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation to Williams Field Services, a U.S. based natural gas infrastructure provider. Sales under these contracts are either at spot prices or at prices set by pricing formulas that incorporate market-based pricing indices. As a result, our revenues, cash flows, and results of operations depend on the market prices of oil and natural gas, which are subject to fluctuations due to market conditions, supply and demand, global economic growth, geopolitical events, environmental regulations, the availability of transport and shipping infrastructure, and other factors beyond our control. These factors include:

- levels of global economic activity which is the main driver of demand for oil and gas;
- the level of global oil and gas supply;
- expectations regarding future supply and demand;
- the availability and capacity of transportation, storage, and refining infrastructure;
- the actions and policies of the Organization of the Petroleum Exporting Countries (“OPEC”) and other major oil and gas producing countries and regions, and their impact on production quotas, output levels, and exports, including any price wars between principal oil producing countries, such as the recent price wars between Russia, Saudi Arabia and the United States, which resulted in significant fluctuations in oil prices;
- the political, economic, and social conditions and conflicts in oil and gas producing and consuming regions, and the potential for disruptions, sanctions, wars, terrorism, cyberattacks, or other events that could affect production, transportation, or trade of oil and gas, including Russia’s ongoing war in Ukraine, hostilities in the Middle East, including the conflict between Israel and Hamas and military operations between Israel, Iran and Iran’s proxies, political instability in Venezuela or the United States or Yemeni rebel assaults on ships crossing the Red Sea, where a majority of the world’s seaborne crude oil flows through;
- the level of oil and gas exploration and development;

- the development and adoption of new technologies, alternative energy sources, or energy efficiency measures that could reduce the demand for or increase the supply of oil and gas;

- the enactment, implementation, or enforcement of new or existing environmental, climate change, carbon emissions, health and safety, tax or other laws and regulations that could affect the production, transportation, or consumption of oil and gas, or impose additional costs, liabilities, or restrictions on our operations; and

- natural disasters, including circumstantial effects of climate change and meteorological phenomena, such as storms and hurricanes, which especially affect the Gulf of Mexico, pandemics, accidents, or other events that could affect the availability or operation of our facilities, equipment, personnel, or suppliers, including third party logistics and transportation.

If the prices of oil and gas decline significantly or for a prolonged period, our revenues, cash flows and results of operations could be adversely and materially affected and we may not be able to recover our costs of production, exploration, and development. Lower oil and gas prices may result in reduced production if the costs of producing from any of our operations no longer generates a sufficient return and we decide to halt our development and exploration plans or suspend or cease production. Because our reserve and resource estimates are estimates of quantities that we can commercially produce, lower oil and gas prices may result in us reducing our reserve and resource estimates and may result in asset impairments and such reductions may affect our ability to access funding. See "—Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves and no longer being commercially recoverable" and "—Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans."

Reduced cash flows as a result of lower oil and gas prices may adversely affect our ability to service our debt. Lower oil and gas prices may also reduce the amount available for us to borrow because the borrowing limit under our RBL facility is based in part on our estimated proved and probable reserves. See "Description of other financing arrangements."

We enter into hedging transactions for oil and gas prices from time to time in accordance with our hedging policy in order to mitigate the effect of price fluctuations and as required by our RBL facility. See "Management's discussion and analysis of financial condition and results of operations—Overview—Key factors affecting our results—Oil and gas prices." However, we will remain exposed to price fluctuations for the unhedged portion of our production, our hedges will expose us to the risk of default from our hedge counterparties and if prices rise, we may recognize losses on our hedges that offset the gains from higher prices on the unhedged portion of our production.

Our production may be lower than expected or we may incur additional costs and liabilities due to a range of production risks.

Oil and gas production is subject to numerous risks that may result in production being interrupted, lower than expected or ceasing earlier than expected or resulting in us incurring additional costs or liabilities. These risks include:

- risks relating to the unpredictable nature of oil and gas reservoirs, including premature decline or total failure of reservoirs, invasion of water into producing formations, encountering unexpected formations or pressures, low permeability of reservoirs and unusual or unexpected rock formations and abnormal geological pressures, all of which may lead to us not being able to conduct drilling operations or drilling operations not resulting in commercially feasible oil and gas production;

- operational risks such as the failure of wellhead, gathering lines, flowlines, pumps or other processing infrastructure or equipment, failure of or damage to transportation infrastructure, blowouts and other uncontrollable flows of hydrocarbons or well fluids, explosions, fires, contamination of oil and gas, oil and other chemical spills, shortages of skilled labor and equipment, long lead and times for certain equipment or contract services, pollution and other environmental risks; and

- risks associated with conducting production, development and exploration drilling operations in offshore locations, including extreme weather conditions (including hurricanes and cyclones, the frequency and severity of which could be exacerbated by climate change), which can interrupt operations and damage equipment and infrastructure, potentially severely, as well as the hazards inherent in marine operations, such as marine vessels capsizing, sinking or colliding and the risks of helicopter operations, and the risk of oil spills in marine environments.

If we are forced to shut-in production, we may incur greater costs to bring associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that it may not be economic to bring such wells back online at low commodity price levels, which may lead to decreases in our proved reserve estimates. See "—Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans" for further details regarding the risks associated with decreases in our proved reserve estimates. If we are able to bring wells back online, there is no assurance that such wells will be as productive following recommencement as they were prior to being shut-in. If any of these risks occur, our production could be interrupted, resulting in our production and revenues being substantially lower than what we expect and could adversely affect our financial condition and results of operations.

All of our Brazilian production is processed through a single floating production, storage and offloading facility, *Cidade de Itajaí*, and all of our US Gulf of Mexico production is processed through a single floating production system. Any disruption to the operation of these facilities could have a significant impact on our production. For further details regarding historical disruptions to our operations at *Cidade de Itajaí*, see "—Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan."

Unplanned partial or full shutdowns could adversely impact our financial condition and results of operations if such shutdowns require substantial costs to remediate or continue for an extended period of time, particularly if production interruptions coincide with a period of relatively higher prices. The impact of production interruptions in a high price environment may be exacerbated by losses on our hedges.

The risk of an interruption to our production may be exacerbated by our reliance on third party operators and infrastructure and the concentration of our operations in a small number of fields in two geographical regions. See "—Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan", "—Our joint venture and farm-in arrangements may expose us to various risks and decrease our ability to manage risks" and "—Our success depends, in part, on our ability and that of the operator of our non-operated assets to develop new oil and gas projects, the failure of which could prevent us from realizing profits, or result in the total or partial loss of our investment."

In addition, in Brazil, exploration, development and production activities are usually described in detail in plans and work programs prepared by the concessionaire/contractor in accordance with the relevant ANP regulations and such plans and programs are assessed and approved by the ANP prior to the commencement of activities comprised therein. If any delays or interruptions cause a material change of scope of an approved plan or program, a revised version must be submitted to the ANP for approval, describing any amendments thereto. Discussions with the ANP concerning plans and work programs may be time-consuming and may impact the relevant operations. In addition, our failure to timely present or have plans and programs approved by the ANP, as well as any failure to duly comply with the requirements of such plans and programs, may lead to the imposition of fines by the ANP and, in the worst-case scenario, to the termination of the relevant concession contract (subject to an administrative proceeding). See "Regulatory overview—ANP."

Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan.

As noted above, all of our Brazilian production is processed through a single floating production, storage and offloading facility*, Cidade de Itajaí*. The *Cidade de Itajaí* is owned by Altera & Ocyan, a joint venture formed between infrastructure service providers Altera and Ocyan, and we have a charter contract that expires in 2026 (with two one-year extension options by mutual agreement). The *Cidade de Itajaí* has a number of systems that lack redundancy, meaning that their failure could result in an interruption of production until they have been repaired. A disruption to the operation of the *Cidade de Itajaí* could result in an interruption to production from our Baúna assets, which would have an immediate impact on our cash flow from operations and profitability, as well as potentially requiring additional expenditure to remedy defects. For example, on March 28, 2023, production on the *Cidade de Itajaí* was shut down after a hydrocarbon leak from pipework within the gas flare system. While the leak was isolated and repaired, we and the floating production, storage and offloading facility operator, Altera & Ocyan, decided to undertake a more comprehensive inspection of the facility's pipework, resulting in a shutdown that extended to 42 days. In November 2023, operational issues in the facility's gas lift dehydration unit led to the formation of hydrates in two wells. We subsequently discovered a mechanical blockage in the gas lift valve of one our wells, SPS-88, which impeded production rates, pending an intervention that we anticipate be completed by the third quarter of 2024 at a cost of approximately US$20-30 million.

Under our charter, we depend on Altera & Ocyan and its personnel to maintain the *Cidade de Itajaí* facility. Altera & Ocyan is also responsible for any replacement costs or costs associated with repairs. We have been working with Altera & Ocyan to address a range of operational issues with the *Cidade de Itajaí* where we have sought improvements, including adding redundancy to a number of key systems. We have also notified Altera & Ocyan of a number of non-compliances for which we believe we are entitled to receive contractual penalties. While we believe that we and Altera & Ocyan are working constructively to resolve the remaining operational issues, a failure by Altera & Ocyan to address the remaining issues would result in an elevated risk of production interruptions. If we are unable to satisfactorily resolve the outstanding contractual items, it may not be possible or desirable to exercise the two one-year options to extend the floating production, storage and offloading facility charter contract beyond its current expiry date in February 2026 (which would require us to provide notice a year in advance) or negotiate an extension beyond February 2028.

If we were required to replace the *Cidade de Itajaí* with a different floating production, storage and offloading facility, we anticipate that we would incur significant additional expenses and our production from Baúna would be interrupted, potentially for an extended period if we were unable to secure a replacement floating production, storage and offloading facility within the timeframe we require.

We also have an operating services contract with OOG-TKP, an affiliate of marine transportation company Teekay, for a range of services on the *Cidade de Itajaí*, including crewing the vessel, managing the handling, processing and storage of crude oil, water injection, gas lift, gas export and transferring crude oil to shuttle tankers. A number of these services are critical to the operation of the facility, and a failure to perform these services with due skill and care could result in production interruptions and damage to the facilities. We have limited ability to directly supervise the performance of these services.

We depend on facilities and infrastructure owned and/or operated by third parties, which may expose us to operational, financial and legal risks that are beyond our control.

In addition to the *Cidade de Itajaí*, our oil and gas production activities depend on a range of other third party facilities and infrastructure. We have used third-party offshore drilling rigs to support our Brazilian exploration and development activities, in particular the *Noble Developer* semi-submersible offshore drilling rig, which is owned and operated by Noble, and we expect to engage third party offshore drilling contractors in the future, including for the SPS-88 well intervention. We also use third party operators in our Brazilian operations to, among other things, provide hydrocarbon spill response equipment, service support vessels for the floating production, storage and offloading facility, including remotely operated vehicles and helicopters, which are (in some cases) required to satisfy the facility's operating license requirements. We depend on ships with dynamic positioning capability to offload our production from the *Cidade de Itajaí*. Dynamic positioning ships are able to maintain their position while offloading using onboard propulsion without the need to anchor or moor. These services may be scarce and may not be readily available at the times and places required or at favorable rates. As a result of our marketing arrangement with Shell, we are able to access Shell's fleet of vessels to offload our production. If Shell's fleet becomes unavailable to us as a result of the termination of our marketing arrangement or otherwise, there may be limited alternatives available to us in Brazilian waters. As a result, offloading our production may become more expensive and/or not immediately available.

The US Gulf of Mexico operations in which we have multiple minority joint venture interests are operated by LLOG. All of our US Gulf of Mexico production is currently processed through the floating production system from three producing areas. LLOG is responsible for managing the day-to-day operations, including the drilling, development, completion, production, maintenance and decommissioning of the wells, subsea infrastructure and facilities, including the floating production system. We rely on the operator to perform these functions in a safe, efficient, compliant and profitable manner, and to provide us with accurate and timely information and accounting. See also "Business—Our production and exploration assets—United States of America."

We do not have direct control over the availability, reliability, capacity, cost, maintenance, IT systems or physical security, operation or compliance of any of the floating production, storage and offloading facility in Brazil or the floating production system in the US Gulf of Mexico and other third-party services, and we may incur liabilities, including liability with respect to government authorities or other third parties, or losses as a result of their failure, disruption, damage, delay, breach of contract, force majeure, environmental incidents, regulatory actions, disputes or other events affecting them or their operators. Any indemnities that we may receive from such parties may be inadequate or difficult to enforce.

Where we do not act as operator of the acreage in which we have an interest, such as in the US Gulf of Mexico, we depend on the operator to conduct exploration and development activities. We may have limited influence or recourse over the operator's decisions, actions or omissions, which may not align with our interests, objectives or expectations. The success and timing of exploration and development activities on properties operated by others depends upon a number of factors that could be largely outside of our control, including but not limited to the timing and amount of certain capital expenditures; the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel; the operator's expertise and financial resources; and approval of other participants in drilling wells.

In addition, we have limited control over the maintenance of safety and environmental standards of the US Gulf of Mexico operations. The operator may incur higher than expected capital or operating expenditures, fail to comply with applicable laws and regulations, encounter operational or technical difficulties, delay or cancel planned activities, or engage in disputes or litigation with us or other co-owners. Any of these events could adversely affect our share of production, revenues, costs, reserves, resources, liabilities and reputation.

LLOG, which operates the Who Dat assets, also relies on a range of third party contractors, including for transportation and logistics services. Oil production from the Who Dat field is transported to the mainland United States via the Mars pipeline, which is a common carrier pipeline operated by a subsidiary of Shell, and gas is transported via the Canyon Chief and Transco pipelines into the Mobile Bay Gas Plant, all operated by Williams. We depend on these operators to maintain and operate this infrastructure safely and effectively. Some of this infrastructure is decades old and may be more prone to failure than more modern infrastructure. If there is a failure at any of these facilities, production may be interrupted from Who Dat until alternative arrangements can be made, which may require the joint venture to construct new equipment and infrastructure in order to access alternative facilities. For example, from May 1, 2024 to May 21, 2024, the Williams Mobile Bay Gas Processing facility will undergo maintenance, which will require us to temporarily utilize an alternative route to market for natural gas at an additional cost of $0.69/mcf and $0.05/gallon NGL costs incurring approximately US$250,000 of additional costs.

Our joint venture and farm-in arrangements may expose us to various risks and decrease our ability to manage risks.

We are a minority, non-operating joint venturer in our US Gulf of Mexico operations. It is likely that we will engage in additional joint ventures in the future, either through farming in to new operations or farming out our existing or future operations, such as Neon in Brazil, if developed. The use of joint ventures and associated farm-in/farm-out arrangements is common in the oil and gas exploration, development and production industry and serves to mitigate the risk and associated cost of exploration, development, production and operational failure. However, disputes or failure of agreement or alignment with joint venture partners, including in relation to operations, budgets, development plans or joint venture audits, our failure as an operator of joint venture or farm-in arrangements or the failure of third party joint venture or farm-in operators or parties, could have a material effect on our business. These arrangements can also decrease our ability to manage risks and costs, particularly where we are not the operator. We could have limited information on, influence over and control of the behavior and performance of these operations. In addition, misconduct, fraud, bankruptcy, noncompliance with applicable laws and regulations or improper activities by or on behalf of one or more of our joint venture or farm-in partners could have a significant negative impact on our business and reputation.

The failure of joint venture or farm-in partners to meet their commitments and share of costs and liabilities can result in increased costs to us thereby adversely impacting our financial condition and results of operations. Additionally, there is a risk that our joint venture partners may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us. If this occurs, our business, financial condition and results of operations may be adversely impacted, and we may lose our investment in such partnerships.

Disagreements and divergent interests with joint venture partners could lead to disputes, which may be disruptive to the joint venture, as well as being expensive, time consuming and may lead to adverse results. See "—Risks relating to our regulatory, tax and legal environment—Our business subjects us to potential liability from litigation, arbitration and regulatory action." The offshore operating agreements governing the operation of the US Gulf of Mexico joint ventures in which we have interests all provide for certain decisions to be made by majority vote. Because we are a minority working interest holder in those fields, the other working interest partners may make those decisions in ways with which we disagree and we will be bound by the result. The offshore operating agreements also provide the operator with significant scope to make operational decisions, including in decisions in the case of an emergency that may involve substantial expenditure, without the advance approval of the other working interest parties. Our dependence on the operator and other working interest owners and our limited ability to influence operations and certain associated costs of properties operated by others could prevent the realization of anticipated results in drilling or acquisition activities. See also "Business—Our production and exploration assets—United States of America."

Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves no longer being commercially recoverable.

We have prepared reserves and resources estimates consistent with PRMS 2018, which is sponsored by, among others, the SPE, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers, and we follow the PRMS 2018 in order to comply with ASX requirements for Australian publicly listed companies. Changes to the PRMS 2018 or any other applicable guidelines or requirements, may also impact our calculation of petroleum reserves and contingent resources estimates. The PRMS 2018 was last updated and released in July 2018, and a key clarification was the requirement for 1P reserves to demonstrate positive economics based on estimated entitlement forecast quantities and associated cash flow. Future changes to PRMS 2018 may result in reductions to our estimates of our petroleum reserves and contingent resources. See also "Cautionary note regarding reserves and contingent resources."

Under the PRMS 2018 framework, reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial and remaining (as of the evaluations effective date) based on the development project(s) applied. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by application of development project(s) not currently considered commercial owing to one or more contingencies, such as projects for which there are currently no viable markets, where commercial recovery is dependent upon technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not approved, or where regulator or social acceptance issues may exist.

Reserves and resources quantities are inherently uncertain and may not materialize. Significant uncertainties are inherent in the reservoir geology, the seismic and well data available and other factors, such as project development, revenues, taxes, development expenditures, quantities of recoverable oil and gas reserves and resources and operating costs, together with relevant commodity prices and evolving regulatory requirements. The process of estimating oil and gas reserves and resources is complex. Estimated reserve quantities are based upon interpretations of geological and geophysical models and assessments of the technical feasibility and commercial viability of producing the reserves. These assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. In addition, the estimates of reserves may change from period to period as the economic assumptions used to estimate the reserves could change from period to period, and as additional geological and engineering data is generated during the course of operations. In addition, we may adjust estimates of reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. Uncertainties are heightened for undeveloped reserves, which are expected to be recovered from new wells on undrilled acreage or from existing wells that require major expenditure for recompletion. As of December 31, 2023, our reserves were mainly developed reserves but we may have significant undeveloped reserves in the future as we expand our business.

Uncertainty in relation to reserves and resources is often expressed as a range of reserves and/or resources levels with associated probabilities. We have recorded reserves and resources in connection with fields of varying maturity levels. During the course of exploration, appraisal, development and continuing operations, the increased quantity and sources of data will generally improve the accuracy of the reserves and resources estimates and narrow the range of uncertainty. However, there is always a risk that the reserves actually produced may vary from the predicted reserves estimate, for example tending to the lower end of the volume uncertainty range, in response to poorer reservoir performance than expected or earlier than expected water influx, or other technical or commercial reasons. In some cases, the stated reserves may, during, or at the end of, field-life, vary significantly from the previous estimates, either upwards or downwards for various technical or commercial reasons, which may have an adverse impact on our revenue and ability to meet our contractual commitments.

We have included in this offering memorandum estimates of our proved, or 1P, reserves, our proved plus probable, or 2P, reserves, our proved plus probable plus possible, or 3P, reserves and our probable, or 2C, contingent resources. Readers should carefully consider the definitions of these categories set out elsewhere in this offering memorandum and understand the degree of uncertainty attached to each category. Particular caution should be applied to our 3P reserve estimates and our 2C contingent resource estimates. 3P reserves include estimated quantities of hydrocarbons, the extraction of which we do not consider probable. Our 2C contingent resources are estimates of hydrocarbon quantities that are not recoverable under current conditions and may never become recoverable. We would not be permitted to disclose our 3P reserves or 2C contingent resources in an SEC registration statement. No assurance can be given that the reserves and resources presented in this offering memorandum will be developed, produced or recovered at the levels presented or that the volumes will be maintained given ongoing evaluation work. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties.

The estimates that we have made at a point of time are also subject to revision as a result of subsequent developments, including changes global commodity prices and the regulatory framework in which we operate, which may adversely impact the commercial recoverability of our reserves. The prices at which we expect to be able to sell the oil and gas when we extract it are critical to our reserves estimates. An extended or substantial decline in oil and gas prices or demand for oil and gas or expectation of such decline may mean that previously booked reserves and resources may no longer be regarded as recoverable, leading to a reduction in reserve and resource estimates.

Similarly, changes to the regulatory framework in which we operate or enhanced environmental scrutiny could result in the extraction of previously booked reserves and resources no longer being commercially viable. These changes include:

- the introduction or increase of a carbon price mechanism or any other mechanism that raises the cost of carbon or greenhouse gas emissions. See also "—Risks relating to our regulatory, tax and legal environment—Laws regulating greenhouse gas emissions could adversely affect the cost, manner and feasibility of doing business and demand for the oil and gas that we produce;"

- any increase in regulatory compliance costs or the imposition of additional restrictions or conditions on our operations, including new requirements for environmental approval or licenses, emission limits, or decommissioning obligations (including security arrangements); and

- a reduction in support or increased opposition to the extraction of hydrocarbons from our stakeholders, such as governments, our communities, customers, suppliers, lenders, investors or activists, that may affect our reputation, social license to operate, contractual arrangements or existing legal rights.

Any of these factors may result in a downwards revision of our reserve and resource estimates. Downward revisions of our contingent and prospective resources resulting from study reviews and/or access to additional data, changes in commodity prices or changes in regulation may result in lower than expected production levels, which could materially and adversely impact our business, financial condition or operational results. See also "—Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans."

The present value of future net cash flows of our proved reserves and the associated PV-10 calculation are not necessarily the same as the current market value of our estimated oil and gas reserves.

You should not assume that any present value of future net cash flows from our proved reserves represents the market value of our estimated oil and gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2023 on assumptions about price and costs. See also "Cautionary note regarding PV-10 values" and "Annex A—Summaries of independent reserve reports" for more information about how these PV-10s were calculated. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues are affected by factors such as among other things:

- the amount and timing of capital expenditures and decommissioning costs;

- the rate and timing of production;

- changes in governmental legislation, regulations or taxation;

- volume, pricing and duration of our oil and gas hedging contracts;

- supply of and demand for oil and gas;

- actual prices we receive for oil and natural gas; and

- our actual operating costs in producing oil and natural gas.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties affects the timing of actual future net cash flows from reserves, and, thus, their actual present value. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans.

We undertake regular reviews of our reserves and resources, including as part of preparing and finalizing our interim and full-year financial statements. We may revise our reserves and resources downwards for a range of factors as described in "—Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves no longer being commercially recoverable."

We recognize an impairment loss when the carrying amount of an asset exceeds its estimated recoverable amount, which is the greater of its fair value less costs of disposal and its value in use. Value in use is primarily based on the asset's estimated future cash flows, discounted to their present value, while fair value is based on discounted future cash flows plus other relevant factors such as value attributable to additional resource and exploration opportunities beyond reserves based on production plans. Any required write-downs or impairments could materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

The expected future cash flow estimate is based on a number of factors, the most important of which are estimates of hydrocarbon reserves and resources, future production profiles, commodity prices, operating costs, foreign exchange rates and carbon price and abatement cost assumptions. Accordingly, if oil and/or gas prices fluctuate, decline or we expect oil and/or gas prices to decline or fluctuate, our estimate of future cash flows may decrease and, as a result we may estimate a lower fair value less costs of disposal and/or value in use.

We also undertake impairment testing of our capitalized exploration and development expenses. We capitalize the costs of successful exploration wells, acquiring interests in new exploration assets and appraisal costs relating to determining feasibility. When the technical and commercial feasibility of an undeveloped field has been demonstrated, we capitalize the costs of development. A write-down of resources associated with a field in development may result in a write-down of the associated capitalized exploration and development expenses. It may also result in us altering our development and production plans in ways that adversely affect the timing and volume of our expected future production. See also "Management's discussion and analysis of financial condition and results of operations—Critical accounting policies—Impairment of oil and gas assets."

Risks related to completed or potential acquisitions may adversely affect our business, including risks related to our ability to realize all of the anticipated benefits of our acquisitions and our ability to integrate our acquisitions successfully.

Our strategy includes seeking to grow our business through acquisitions of additional assets or businesses, such as our recently completed acquisition of interests in US Gulf of Mexico assets from LLOG, and we regularly evaluate acquisition opportunities and engage in negotiations with third parties with respect to new opportunities.

Acquisitions involve numerous risks, including:

- inadequate due diligence leading to our failure to properly understand and value an acquired asset, including failing to identify material risks;
- changes in our future capital and operating expenditure obligations, which may impact our funding requirements;
- incurring liabilities resulting from previous activities of operators and joint venture partners, or from any areas not disclosed or uncovered during due diligence processes;
- the costs and management time required to integrate new businesses into our operations and execute growth identified at the time of entering a transaction may not be realized post-completion;
- risks associated with the entry into any new jurisdiction for which we have limited experience;
- operating a larger organization;
- coordinating geographically disparate organizations, systems and facilities;
- diverting management's attention from regular business concerns;
- failing to execute on integration plans and maximize cost savings, including with respect to corporate, technological and administrative functions;
- failing to operate new assets as effectively as previous owners; and
- failing to successfully develop growth projects we acquire.

We conduct a due diligence investigation in connection with any acquisition, and we may rely on employees or third parties we engage as part of the due diligence process to conduct such due diligence investigations. We may also rely on information provided by or on behalf of the seller or third parties we engage, and we may not be able to verify the accuracy, reliability or completeness of such information. For example, we employed several third party advisers to assist us with the due diligence process for the acquisition of interests in our US Gulf of Mexico assets from LLOG. However, the information we obtain in connection with an acquisition may be incomplete, incorrect, inaccurate or misleading. The analysis we and our advisers undertake in connection with an acquisition may result in conclusions and forecasts that are inaccurate or are not realized, whether because of flawed methodology, misinterpretation of data or otherwise. Due to competitive or other pressures, we may need to commit to an acquisition before we have all of the information and analysis we would like. As a result of any of these factors, the actual characteristics and performance of an acquired asset may be materially different than we expect, which may have an adverse impact on our financial position and results of operations.

When we acquire another company, the liabilities (including financial debt, whether assumed or refinanced) of the company acquired may become our liabilities, which may increase our financial leverage and result in changes to other credit metrics, which could adversely impact our credit capacity and credit ratings.

There may be threatened, contemplated, asserted or other claims against the assets we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may be successful in obtaining contractual indemnification for preclosing liabilities, including environmental liabilities, but we expect that we will generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, even if we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and could potentially expose us to non-indemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Our unaudited pro forma combined financial information is for informational purposes only and is not intended to reflect what our actual results would have been had our acquisition of interests in US Gulf of Mexico assets from LLOG occurred on January 1, 2023 and may not be a reliable indicator of our future results.

The historical financial statements included in this offering memorandum consist of separate consolidated financial statements of Karoon Energy and the statements of revenues and direct operating expenses of the Who Dat assets. These financial statements were used to create the unaudited pro forma combined financial information included in this offering memorandum under "Selected unaudited pro forma combined financial information." The unaudited pro forma combined financial information is for illustrative purposes only. It does not reflect the costs of any integration activities or transaction-related costs or incremental capital expenditures that may be necessary for us to realize the anticipated benefits from the acquisition. Accordingly, the pro forma combined financial information included in this offering memorandum is not intended to, and does not purport to, represent what our actual results would have been if our acquisition of interests in US Gulf of Mexico assets from LLOG occurred on January 1, 2023, or what our results of operations will be in the future. In addition, such unaudited pro forma combined financial information is based in part on certain assumptions regarding the acquisition that we believe are reasonable and comply with applicable accounting guidance. The assumptions used in preparing the unaudited pro forma combined financial information may not prove to be accurate, and other factors may affect our financial condition and results of operations. Actual results may differ materially from the assumptions used to present the accompanying unaudited pro forma combined financial information. See also "Unaudited pro forma combined financial information."

The unaudited pro forma combined financial information does not include all the information and disclosures required by IFRS for a complete set of financial statements. The unaudited pro forma combined financial information has been derived from and should be read in conjunction with our consolidated financial statements and the statements of revenues and direct operating expenses and related notes of the acquired assets, as applicable, and the sections titled "Management's discussion and analysis of financial condition and results of operations" included elsewhere in this offering memorandum.

Our success depends, in part, on our ability and that of the operator of our non-operated assets to develop new oil and gas projects, the failure of which could prevent us from realizing profits, or result in the total or partial loss of our investment.

We have a number of assets in the early stages of being evaluated for future exploration or development, including the Neon discovery in Brazil and the Who Dat East, Who Dat South and Who Dat West fields in the US Gulf of Mexico. Exploration and appraisal activities require developers of oil and gas assets to spend significant amounts of capital—in particular to drill exploration and appraisal wells—based on limited geological data. There can be no assurance that our or our joint venture's exploration or appraisal activities will confirm that the identified fields contain sufficient quantities of hydrocarbons in formations amenable to economic extraction to justify development.

Once we, or we and our joint venture partners, decide to develop a field, we will face a range of risks that are common to major project execution. These include the risk that the project may cost more or take longer to complete than we expect or that it may fail to perform as planned, resulting in inadequate returns on our investment or that the market for such products will change during the development phase. The risks in developing major projects include:

- delay in or failure to obtain and maintain the necessary government approvals or changes in the regulatory requirements during the development process;

- failures in design, engineering or construction;
- failures by contractors to perform their obligations, including the delivery of projects or equipment on time and to the necessary specifications;
- procurement issues, including equipment fabrication delays and logistical and sourcing challenges due to disruption in global supply chains, labor shortages, inflation, and geopolitical instability;
- unexpected geological conditions, including as a result of failure to correctly interpret geological data;
- unanticipated increases in costs, including for contractors or equipment;
- adverse weather conditions and natural disasters;
- environmental, health and safety or social license issues; and
- inadequate governance, risk management and decision-making.

Developing major oil and gas projects takes a number of years. During this period, market conditions, including those relating to costs, supply and demand fundamentals, financing conditions, geopolitical conditions (including sanctions) and the status of counterparties (including contractors and off-take partners) may change from those that we have forecasted, and these changes may adversely impact our ability to deliver on our various project objectives, delay the revenue coming from these operations or make a project not economically viable or result in additional unexpected investments. See also "—We depend on facilities and infrastructure owned and/or operated by third parties, which may expose us to operational, financial and legal risks that are beyond our control" and "—We may be unable to access the infrastructure, equipment, goods and services we need to operate our producing assets and develop our growth projects."

In addition to financial losses, poor or failed delivery of major projects could result in damage to our reputation and relationships with our project partners, threats to our social license to operate, reduced workforce prospects and reduced ability to invest in our business.

Any of these events may cause changes to the development plans for our Brazilian assets previously approved by ANP. Any such changes could have a material effect on our expected capital expenditure and the timelines associated with the development of our assets. See the last paragraph of "—Our production may be lower than expected or we may incur additional costs and liabilities due to a range of production risks." for further risks regarding ANP's oversight of exploration and development activities.

We may be unable to access the infrastructure, equipment, goods and services we need to operate our producing assets and develop our growth projects.

We require a range of infrastructure, equipment, goods and services to operate our producing assets and develop our growth projects. Some of these items can be scarce and subject to cyclical availability and may not be readily available at the times and places required. In particular, offshore drilling rigs are in high demand and it can be difficult to secure appropriate rigs at the times required to execute our plans. In addition, there are long lead times for customized items such as wellheads. Periods of particularly high demand, which usually coincide with periods of elevated oil prices, can also result in increased prices for long-lead items, including wellheads, remotely operated vehicles, umbilical systems and pipe and rig leases and increased wages of the crews that operate them. If we or the operators of our joint venture assets are unable to secure drilling rigs at the times we need them, our exploration, appraisal and development plans will not proceed on the schedule we have set, which may cause a delay in our path to productivity for an asset and may require us to change our development plans with ANP with respect to our Brazilian operations.

The marketability of our production depends upon the availability, proximity, operation and capacity of oil and gas gathering systems, pipelines and processing facilities. The lack of availability or capacity of this infrastructure could result in the shut-in of producing wells or delays or discontinuance of development plans for our properties. The disruption of these gathering systems, pipelines and processing facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products.

High demand for the items we need could drive up prices, increasing our costs, which could have a material adverse effect on our operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of our properties, our planned level of spending for exploration and development and the level of our reserves. Prices for the materials and services we depend on to conduct our business may not be sustained at levels that enable us to operate profitably.

We and our current or future offtakers may also depend on the availability of storage tanks and transportation systems, such as pipeline systems, oil tankers and onshore terminals, which may be subject to capacity constraints and price increases. If we are unable to sell the oil and gas we produce in a timely fashion, or if increased prices for transportation and storage infrastructure reduce the prices we receive for our production, our cash flow and results of operations may be adversely affected.

Our industry and the broader global economy have been experiencing significant inflationary pressures. If these conditions persist, they may impact our ability to procure labor, materials and equipment on a cost-effective basis, or at all, and, as a result, our business, financial position and results of operations could be adversely affected.

Since 2021, we have experienced inflationary pressures resulting in increases in the cost of labor, materials and equipment, including fuel, field services and field equipment, which, in turn, caused our capital expenditures and operating costs to rise. These inflationary pressures have been largely as a result of supply chain disruptions following the COVID-19 pandemic and, more recently, increased geopolitical instability, and the resulting increase in global demand for certain field services and equipment, challenges in the supply of labor and/or labor shortages. While COVID-19-related supply pressures have eased, inflation remains a challenge due to increased activity levels in the oil and gas industry and we may continue to experience supply chain constraints and inflationary pressure on our cost structure in future periods. If inflationary conditions persist or worsen, they could result in increased capital expenditures and operating costs, reduced margins and production delays and adversely impact the timing and results of operations from our major projects. As a result, our business, financial position and results of operations could be adversely affected.

Historically, Brazil has suffered high rates of inflation. The Brazilian federal government has adopted various measures in response to inflation negatively affecting the Brazilian economy. There is no guarantee that the Brazilian economy will not be affected in the future by new inflationary pressures. We are party to various contracts that are adjusted for inflation, and our ability to meet our obligations may thus be adversely materially impacted if inflation were to persist in Brazil. Inflationary pressures may also reduce our ability to access foreign financial markets, affect the ability of counterparties to honor their commitments, and lead to additional government interventions in the Brazilian economy.

The Brazilian Central Bank's Monetary Policy Committee ("COPOM") periodically establishes the SELIC rate, the basic interest rate for the Brazilian banking system, which serves as an important instrument for compliance with inflation targets. The basic interest rate has fluctuated frequently in recent years. COPOM has frequently adjusted the basic interest rate due to economic uncertainties and to achieve the currency stability objectives determined by the monetary authority. On August 4, 2022, the SELIC reached 13.75%, its highest level in five years, after a decision taken by COPOM commenting that the various measures of underlying inflation are above the range compatible with meeting their inflation target. In September 2023, COPOM began reducing the SELIC, which reached 10.75% in its latest update as of March 20, 2024. Increases in the basic interest rate may adversely affect our results of operations, through a reduction in the demand for credit, an increase in funding costs, and an increase in the risk of counterparty defaults.

Our business, financial condition and results of operations may be materially adversely affected by any negative impact on the global economy and energy and capital markets resulting from the Russian invasion of Ukraine, tensions in the Taiwan Strait and in the Middle East or any other geopolitical events.

In February 2022, Russia launched a military invasion of Ukraine. In response, various Western allied countries, including the member states of the European Union, the United Kingdom, the United States and Australia implemented a series of wide-ranging economic sanctions and export controls against Russia, and Russian officials have made a variety of threats against countries that have supported Ukraine. The outcome and the broader consequences of the conflict are unpredictable. In October 2023, armed conflict escalated between Israel and Palestine after an attack on Israel by Hamas and recently there have been military operations between Israel, Iran and Iran's proxies. There is a risk that these events may lead to a wider conflict in the Middle East. In addition, recent years have seen high levels of tension in the Taiwan Strait as a result of indications that China may contemplate military action against Taiwan.

The consequences of these conflicts and any other geopolitical events may negatively impact other regional and global economies, on various sectors, industries and markets for securities and commodities globally. Military conflicts may result in hostile actions outside of the principal sphere of conflict, such as disruption of shipping lanes (including those used for energy transport) and cyber attacks. Any military conflict may also cause regional instability, geopolitical shifts, and could materially adversely affect global trade, currency exchange rates, regional economies and the global economy. The extent and duration of the war in Ukraine or conflicts in the Middle East, the likelihood of future hostilities, the extent, duration and impact of existing and future sanctions, the potential blockade of key trade corridors, other market disruptions and volatility, and the result of any diplomatic negotiations are highly uncertain. These and any related events may impact global energy prices, increase our production costs or lead to project delays, any of which could have a material adverse impact on our business, financial condition and results of operations.

If we are unable to replace our existing reserves due to competition with a range of industry participants with respect to acquiring new reserves and the capital-intensive nature of exploring, developing and acquiring reserves, we may not be able to sustain production over the longer term.

Our longer-term prospects depend on us replacing existing oil and gas reserves as they are depleted through production, from either exploration or acquisition. We have rights to extract or have access to a finite amount of oil and gas reserves, which will be depleted over time. Producing oil and gas reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful exploration, appraisal and development and exploitation activities or acquire properties containing reserves, our reserves will decline as those reserves are produced. We expect to reach the end of field life for our Baúna reserves by 2031 and 2032 for 1P and 2P reserves, respectively.

Securing new sources of hydrocarbons is a challenging and competitive undertaking. Additionally, the availability of cash and financing to fund acquisitions of new sources of hydrocarbons may be adversely impacted by market conditions. Exploration for oil and gas resources is a high-risk endeavor subject to geological and technological uncertainties and the failure to replace reserves is a risk inherent in our industry. Exploration activity involves the interpretation of seismic and other geological and geophysical data, which does not always successfully predict the presence of commercial quantities of oil and gas. The cost of drilling, completing, and operating wells may be curtailed, and drilling operations may be delayed or canceled as a result of a variety of factors including: unexpected adverse conditions, unexpected drilling conditions, irregularities in pressure or formations, equipment failure or accidents, fire, explosions, blowouts, weather interruptions, miscalculations or accidents, increases in the cost of or shortages or delays in the availability of rigs and equipment leading to the abandonment of the well(s) and a total loss of our investment. Future developments may be affected by unexpected reservoir conditions, which negatively affect recovery factors or flow rates. Our future oil and gas reserves and production, and therefore our cash flows and results of operations, depend on our success in efficiently developing our current reserves and economically discovering or acquiring additional recoverable reserves.

We compete for reserves acquisitions, exploration leases, licenses, concessions and marketing agreements against a wide range of industry participants, many of which have significantly larger financial and other resources than we have. See "—The oil and gas industry is highly competitive." These companies may be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects, including operatorships and licenses, than our financial or human resources permit. If we are unsuccessful in discovering or acquiring new resources and developing and producing additional reserves, then we may not meet our long-term goals for growth or sustainability in production, and our future total reserves and production may decline and adversely affect our results of operations and financial position.

The oil and gas industry is highly competitive.

The oil and gas industry is characterized by intense competition among a wide variety of participants, including the major oil companies, government-backed national oil companies, independent oil and gas concerns, individual producers, gas marketers and major pipeline companies. Many of these competitors have significantly greater resources than we have, and some may have favored access to governments and other regulators in certain jurisdictions. Competitors may also have a greater ability to continue drilling activities during periods of low oil and gas prices and to absorb the burden of current and future governmental regulations and taxation.

In addition to competing to acquire additional oil and gas reserves and resources, we compete with other industry participants to hire skilled employees, to retain third party service providers, to procure equipment, to access existing and innovative technologies and to access capital. If we are unable to compete successfully in the future, our future revenues and growth may be diminished or restricted.

Competition may result in us failing to secure resources that we need to operate and expand our business or may result in us having to pay higher prices than we expect, which could increase our costs, delay our projects or result in interruptions to our production.

New technologies may cause our current exploration and drilling methods to become obsolete, and we may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, and that may, in the future, allow them to implement new technologies before we can. We rely heavily on the use of advanced seismic technology to identify exploitation opportunities and to reduce our geological risk. Seismic technology or other technologies that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

Our production, revenue and cash flow from operating activities are derived from only two main production assets.

We have two main production assets, comprising six operating oil fields; the Báuna asset, which we operate offshore Brazil, and the Who Dat asset, in which we have non-operating interests in the US Gulf of Mexico. We also hold exploration and development acreage adjacent to Báuna and Who Dat. As such, the success and performance of our operations may be disproportionately exposed to the effect of regional conditions such as:

- severe weather, such as hurricanes, winter storms, loop currents, tornadoes and other adverse climatic conditions;

- changes in local laws and regulations affecting our operations (including regulations that may, in certain circumstances, impose strict liability for pollution damage or require posting substantial bonds to address decommissioning costs) and interruption or termination of operations by governmental authorities based on environmental, safety or other considerations;

- local price fluctuations and other regional supply and demand factors, including availability of gathering, pipeline, transportation and storage capacity constraints;

- production delays or decreases in the regions limited potential customers;

- infrastructure capacity and availability of rigs, equipment, oil field services, supplies and labor;

- changes in the status of pipelines that we depend on for transportation of our production to the marketplace; and/or

- changes imposed as a result of litigation or by a new government in Brazil or a new presidential administration or Congress in the United States that may result in added restrictions and delays or prohibitions in offshore oil and gas exploration and production activities, including with respect to leasing, permitting, site development or operation in federal waters or hydraulic fracturing.

Because all or a number of our operating oil and gas fields could experience many of the same conditions at the same time, these conditions may have a relatively greater impact on our results of operations than they might have on other producers who have a larger number of assets across wider geographic areas.

Increasing attention to ESG matters may adversely impact our business and strategic objectives.

In recent years, increasing attention has been given to corporate activities related to ESG matters in public discourse and the investment community. A number of advocacy groups have campaigned for governmental and private action to promote change at public companies related to ESG matters, including through the investment and voting practices of shareholder activists, investment advisers, private fund managers, public pension funds, superannuation funds, sovereign wealth funds, universities and other members of the investing community. These activities include increasing attention and demands for action related to climate change and promoting the transition away from fossil fuel as a primary energy source. A failure to understand and respond to investor or public expectations and standards, which are evolving, could cause us reputational harm and may adversely impact our business and strategic objectives.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Also, some stakeholders have been urging lenders to limit funding to companies engaged in practices that are perceived to be detrimental to the environment. Unfavorable ESG ratings and investment community divestment initiatives may lead to negative investor sentiment toward us, which could have a negative impact on our access to and costs of capital. See also "—Risks relating to our financial arrangements—If we are unable to raise funds on favorable terms, including in order to fund our growth projects and any future acquisitions and refinance our existing debt, our business could be adversely affected."

External expectations in relation to performance and reporting across material ESG and sustainability topics, including climate change, environmental performance and modern slavery continue to evolve rapidly. As an ASX-listed company, we currently report against our aspirations, targets and performance across five sustainability pillars: health, safety and security, climate, people, community and environment. Any material incidents or issues that develop within any of these key ESG topics, or a failure to continue to adapt to external expectations in relation to our ESG disclosures, may have a material impact on our access to capital, license to operate, operational or financial performance and our reputation.

Our aspirations, targets and disclosures related to ESG matters, including our decarbonization strategy, expose us to risks, including risks to our reputation, results of operations and financial position.

We have announced a range of ESG goals and targets, and we expect our performance against those targets and the quality of our reporting of our relevant ESG measures to be closely scrutinized by investors, regulators and community and advocacy groups.

In particular, we have stated goals for our carbon emission performance, including continuing to be carbon neutral at the Baúna project (including by the use of offsets) with respect to Scope 1 and 2 emissions. Carbon neutral refers to reducing or avoiding operational Scope 1 and 2 greenhouse gas emissions, acquiring carbon offsets to balance the remaining Scope 1 and Scope 2 emissions, and investing in carbon sequestration initiatives. We also aim to achieve net zero Scope 1 and 2 emissions at the Baúna project by 2035. Net zero refers to reducing Scope 1 and 2 greenhouse gas emissions as far as practical and offsetting the residual greenhouse gas emissions through investment in carbon removal or sequestration initiatives equal or greater to the residual greenhouse gas amount.

We expect that we will need to acquire carbon offset credits in order to meet our stated carbon emissions performance goals. Any changes in regulations on carbon credits, including the potential adoption of the Brazilian Greenhouse Gas Emissions Trading System, may affect if and how we are able to achieve our carbon neutral and net zero goals. See "—Risks relating to our regulatory, tax and legal environment—Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position" for more information.

In recent years, there has been rising demand for carbon offset credits in light of a rising number of businesses implementing net zero goals. We cannot guarantee that there will be sufficient carbon offset credits available for purchase when we require them or that offsets we do purchase will successfully achieve the emissions reductions that they represent.

Our ability to implement our climate transition strategy and achieve our targets, including our target of becoming a net-zero for Scope 1 and 2 emissions business by 2035, is subject to risks, including:

- our ability to continue to reduce Scope 1 and Scope 2 emissions in our business;
- the continuing progress of commercially viable technologies to avoid carbon emissions;
- the availability of suppliers that can meet our sustainability and other standards;
- the availability and cost of high-quality, removals-based offsets;
- evolving legislative and regulatory requirements affecting ESG standards, climate goals and obligations, the validity of removal-based offsets and our disclosures;
- evolving standards for tracking and reporting on emissions and emission reductions and removals;
- customers' preferences and use of our products or substitute products;
- the availability of funds to finance initiatives to achieve our targets, including investments in carbon projects; and
- actions taken by our competitors in response to legislation and regulations.

The standards for tracking and reporting on ESG matters continue to evolve. Our selection of disclosure frameworks that seek to align with various voluntary reporting standards may change from time to time and may result in a lack of comparative data from period to period. Disclosure relating to ESG matters is sometimes based on assumptions and calculations that may or may not be representative of actual or forecast risks or events, including any costs associated therewith. Such assumptions and calculations are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved. Our processes and controls may not always align with evolving voluntary standards for identifying, measuring, and reporting ESG metrics. Our interpretation of reporting standards may differ from those of others, and such standards may change over time, any of which could result in significant revisions to our goals or reported progress in achieving such goals. In addition, regulatory authorities may mandate compliance with certain standards and reporting metrics or require us to audit our ESG data, which may result in increased costs.

Our efforts to achieve ESG aspirations and targets may increase costs or limit or impact our business plans and financial results, potentially resulting in the reduction to the economic end-of-life of certain assets, an impairment of the associated net book value, among other material adverse impacts. Our failure or perceived failure to pursue or fulfill our ESG aspirations and targets or to satisfy applicable reporting standards within the timelines we announce or any perception that we have failed to act responsibly with respect to ESG matters could have a negative impact on investor, community and consumer sentiment towards our business, affect third-party ratings for our approach to ESG matters, increase our cost of capital and expose us to government enforcement actions, private litigation, including class actions and activist campaigns, which may include seeking to pursue binding motions at shareholder meetings, among other materially adverse consequences. See also "—Risks relating to our regulatory, tax and legal environment—Our business subjects us to potential liability from litigation, arbitration and regulatory action."

We rely on a small number of customers for our sales of oil and gas.

We sell all of our oil production from Baúna under a marketing arrangement with SWST, which is a member of the Royal Dutch Shell Plc group. We sell our share of crude oil from Who Dat to BP Products North America Inc., a member of the BP Plc group under a month-to-month evergreen crude oil purchase agreement. We sell our share of natural gas from Who Dat on a six-month seasonal contract basis to BP Energy Company, which is also a member of the BP Plc group, under a gas purchase contract, and we sell our share of natural gas liquids under a life-of-asset sales agreement at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation to Williams Field Services, a U.S. based natural gas infrastructure provider. If our counterparties or we were to discontinue either of these relationships, any new marketing arrangement we enter may be on less favorable terms and we may incur additional costs to facilitate our marketing and sales. We are also exposed to the risk that SWST, BP Products North America Inc., BP Energy Company or Williams Field Services may fail to settle their payment obligations to us on time. We expect that our contracted receivables under these arrangements will generally constitute substantially all of our trade debtors at any given time. At December 31, 2023, our trade debtors balance was US$40.0 million. If SWST, BP Products North America Inc., BP Energy Company or Williams Field Services fails to meet its obligations to us, it could have a significant adverse effect on our cash flow and liquidity.

An increase in the use of alternative sources of energy could substantially affect the demand for fossil fuels, including the oil and gas that we produce.

The world is experiencing a transformation in the manner in which energy is being produced and consumed. This energy transition involves reducing CO2 emissions, applying new technologies to increase productivity, and increasing the use of alternative sources of energy, such as natural gas, and wind and solar power. Changes to the composition of the global energy matrix and the costs of alternative sources of energy could affect the demand for hydrocarbons and fossil fuels, including the oil and gas that we produce, and could adversely and materially affect us. Additionally, the transition to alternative energy sources may be accelerated by tax advantages and other incentives intended to promote the use of alternative energy, fuel sources or low-carbon technologies. For example, the U.S. Inflation Reduction Act implements various incentives for low carbon activities, including carbon capture and storage and the production of hydrogen and sustainable aviation fuel. These incentives could negatively impact supply and/or demand for our oil and gas products in the future.

We may be adversely and materially affected in the event of a decrease in the demand for oil and natural gas. Additionally, a significant increase in the supply of electricity generated by using alternative fuels could result in a reduction of the price of electricity to end users and adversely affect the demand for oil and natural gas.

We cannot guarantee that future increases in oil and natural gas prices, reductions in the prices of alternative fuels, incentives for the use of alternative energy sources or the generation of electricity from such sources will not have a significant adverse effect on us.

Additionally, the development and implementation of new technologies could result in a significant acceleration in the energy transition. We cannot predict if and when new technologies will become available, the migration flow to these new technologies, as well as their acceptance, and associated costs. The advances in the development of alternative energy sources could significantly reduce the demand for fossil fuels, which means reduced demand for oil and natural gas, which could have a material adverse effect on us.

We could incur substantial costs if we fail to ensure the safety of our employees and contractors.

The nature and complexity of our operations and the environments in which we operate pose risks in relation to the health and safety of the employees and contractors who work in our operations, including risks associated with travel to and from operations. Potential causes of health and safety risks include the failure to control energy or heat during high-risk activities, equipment being operated outside safe operating limits, inadequate and poor implementation of the company management system, poor design and maintenance of physical assets and systems, lack of awareness of major accident prevention processes, insufficient workforce competence, poor practices to identify and escalate risks, failure of third parties to design and implement safe systems, external events such as weather, terrorism and pandemics, and inadequate work planning and resourcing, supervision and contractor management, risk management and controls. If we acquire new operations, these risks may be elevated as we integrate another operator's health and safety practices with our own.

If a safety incident occurs, or we identify an unsafe condition in our operations, we may decide or be required by applicable regulations to shut down the operation until the circumstances have been investigated and remedial action completed.

Any failure to provide safe environments for our workforce, contractors and the public could lead to injury or loss of life, increased operating costs, legal liability, regulatory action, loss of operating licenses, damage to our reputation, negative impacts to staff engagement and poor community and investor sentiment.

Offshore oil operations involve a higher level of operational risk than onshore oil operations and require intensive capital expenditures to access, bring online and repair, which may adversely and materially affect us.

Our oil and gas operations only consist of offshore fields, including deep-water offshore fields. Activities in offshore fields involve greater risks related to mechanical problems, especially when compared to onshore activities, as they require more time and employ more advanced technologies, which results in a higher risk of technological failure and higher costs, increasing the risk of occurrence of accidents involving oil spills, which require the suspension of drilling and production activities.

Offshore operations require intensive capital expenditures to access, bring online and repair, which may increase the financial and operating risks of our standard procedures. These operations are also subject to risks inherent to maritime operations, including maritime disasters and pollution, total loss of vessels, government requirements, inactivity of vessels, defects in equipment, fire, explosions, ship turning, shipwreck, stranding, collision, damage due to adverse weather, risks associated with transshipment and infestations. Due to the limitation and high cost of infrastructure, certain discoveries of offshore reserves may not be economically viable, and if developed, they involve a greater risk of not providing the expected results. Such risks and conditions may materially and adversely affect us.

Our insurance arrangements may be inadequate to cover losses arising from our operations.

We maintain insurance coverage limiting financial loss resulting from certain operating and external hazards. We believe the nature and extent of our insurance cover is reasonable, given the nature of our operations and the availability and cost of insurance, and consistent with industry practice. However, our insurance does not cover all of the risks and potential losses we face, including because insurance is not available for certain risks, we consider the premiums too high relative to the risk or we elect to self-insure by setting aside amounts of cash or liquid securities that we deem sufficient to cover the occurrence of any such risks. We have insurance policies for general liability, physical damage to our oil and gas properties, oil pollution, constructions risk, workers' compensation and employers' liability and other coverage. Additionally we currently carry loss of production insurance, however this insurance is subject to limitations and exclusions, including that it is subject to a 60-day risk retention and does not cover loss of production from named storms, such as hurricanes and cyclones. Loss of production insurance is expensive and may become more expensive in the future. We may discontinue loss of production insurance in the future, particularly if we are able to diversify our base of producing assets.

Our insurance is also subject to deductibles that have to be met prior to recovery and limitations on the insurers' liability with respect to individual claims and the aggregate of our claims. As a result, even if we are insured for an incident, our insurance cover may be insufficient to cover our losses. In addition, insurers may dispute that they are liable or the extent of their liability. The occurrence of a significant event that we are not fully insured against could have a material adverse effect on our financial condition and results of operations. Additionally, insurance policy coverage is conditioned to the payment of the respective premium. If we fail to pay these premiums, we could be placed at risk in the event of an accident since the damages would not be covered by the insurer, which could adversely affect us.

In response to increased premiums or other factors, we may in future change our insurance coverage in ways that increase our exposure to uninsured risks and new risks may emerge for which insurance is not available or too expensive, including climate-related risks. If we make claims under our insurance, our insurers may subsequently increase our premiums or place additional limitations or conditions on our coverage.

We cannot assure that we will be able to maintain our insurance policies in the future at reasonable commercial rates or on acceptable terms with the same insurers or similar insurers, which could increase our costs and, as a result, adversely affect us. We could also be held legally liable to pay damages to third parties as the result of an accident. If any of these factors occur, we could be adversely affected.

The loss of key personnel or a shortage of skilled and semi-skilled labor could adversely affect our business, results of operations and financial position.

We require excellent leaders across our organization who can lead various types of skilled and semi-skilled workers, including employees and contractors, from a range of professions, disciplines, trades and vocations. Our future success is significantly influenced by the expertise and continued service of certain key executive and technical personnel. We cannot assure you that individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have an adverse effect on us and our operations.

The demand for skilled workers in our industry is high, and the supply is limited. In addition, our industry has lost a significant number of experienced professionals over the years due to its cyclical nature, which is attributable, among other reasons, to the volatility in commodity prices.

Constraints on our ability to hire and retain labor with appropriate skills and capabilities could cause a shortage of workers for our company or put increased pressure on wages and costs, which could increase our capital expenditure and operating costs. A considerable period of training and time may be required before new employees and contractors are equipped with the requisite skills to work safely and effectively. We also depend on the ability of our contractors and our joint venture partners to attract and retain suitably skilled and experienced personnel, particularly Altera & Ocyan and LLOG. Our failure, or the failure of our key contractors and joint venture partners, to obtain and retain workers and key personnel could cause a labor capacity shortfall within our business, threaten our ability to deliver on our objectives and have an adverse effect on our business, results of operations and financial position. Similarly, interference with the availability of labor due to industrial action and our inability to secure working visas for overseas labor could also impact negatively on our business performance. Negative perceptions of the oil and gas industry may also affect our ability to recruit.

We rely on IT systems to operate our business, and the failure to protect these systems against cyber security risks, data management risks and other similar incidents could adversely affect our business and disrupt operations.

Our operations rely on a number of IT systems, applications and business processes utilized in the delivery of business functions. Our business depends on computer systems and network infrastructure. In addition, we depend on the integrity of the IT systems of our contractors and joint venture partners, particularly the IT systems used to operate the floating production, storage and offloading facility, *Cidade de Itajaí* and the IT systems used to operate the Who Dat floating production system.

Cyber security risks, including threats to our and our contractors' IT systems from computer viruses, unauthorized access, cyber-attacks and other similar disruptions, have evolved rapidly and can impact all sectors of the economy, including the energy industry. Computers and telecommunication systems are an integral part of our exploration, development and production activities and the activities of our business partners. We use these systems to analyze and store financial and operating data and to communicate within our company and with outside business partners. Technical system flaws, power loss, cyber security risks (including cyber or phishing-attacks), unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, ransomware, and other cyber security issues could compromise our computer and telecommunications systems or those of our business partners and result in disruptions to our critical business processes or the access, fraud and disclosure or loss of our data and commercially sensitive information. In addition, computers control oil and gas production, processing equipment, and distribution systems globally and are necessary to deliver our production to market. A disruption, failure or a cyber-breach of these operating systems, or of the networks and infrastructure on which they rely, could damage critical production, distribution and/or storage assets, delay or prevent delivery to markets, and make it difficult or impossible to accurately account for production and settle transactions. As a result, any such disruption, failure or cyber-breach and any resulting investigation or remediation costs, litigation or regulatory action could lead to reputational damage and have an adverse impact on our results of operations and financial position. In addition, as technologies evolve and cyber security attacks become more sophisticated, we may incur significant costs to upgrade or enhance our security measures to protect against such attacks, and we may face difficulties in fully anticipating or implementing adequate preventive measures or mitigating potential harm.

In addition, we manage personal and sensitive data. There is a risk that poor decisions may be made due to data quality issues or failing to appropriately manage and maintain our data. This includes the capture, processing, distribution, retention and disposal of data. Failure to appropriately manage and maintain our data, including use of data in a manner inconsistent with our obligations and values, or not complying with data management regulatory obligations, may result in a loss of trust, operational disruptions, financial losses or regulatory action.

We may not generate sufficient operating cash flow to make contingent consideration payments we owe to Petrobras.

The agreement under which we acquired Baúna from Petrobras requires us to pay contingent consideration of up to US$285 million plus interest of 2% per annum accruing from January 1, 2019. The amount of this contingent consideration is dependent on future oil prices each calendar year from 2022 to 2026 inclusive, and we are required to begin making payments when the annual average Platts Dated Brent oil prices threshold is above US$50 a barrel. Based on our FY22 internal forecasts, which align with our current internal forecasts, we have assumed that the average Brent crude oil prices from 2022 through 2026 would exceed the US$70 per barrel threshold such that we will have to pay the maximum amount of contingent consideration under this arrangement for each calendar year from 2022 through 2026. This led to us recognizing the present value of the entire contingent consideration arrangement in FY22. To date, we have paid US$170.5 million of this obligation, which includes US$14.5 million of interest. See "Management's discussion and analysis of financial condition and results of operations—Quantitative and qualitative disclosures about market risk—Commodity price risk" for details of the calculation of timing of these payments. Because these payments are tied to oil prices, we will need to generate sufficient cash flow from our Baúna operations to make the required payments. If production is interrupted, or we produce at lower rates than we expect, our operating cash flow may be insufficient to make these payments and we may need to use cash from other sources, including cash flow from other operations or additional borrowings, which may affect our ability to pursue our other objectives, including our growth plans. If we were unable to make a payment of contingent consideration to Petrobras, we would be in breach of contract and subject to the risk of Petrobras bringing a claim for specific performance under the Brazilian Civil Code against us, which could materially impact our financial position and ability to operate our business.

Any outbreak of a contagious disease may adversely affect our business, financial condition and results of operations.

Any outbreak of a contagious disease may adversely affect our business, financial condition and results of our operations. For example, our business and operations were adversely affected by the COVID-19 pandemic and the associated reduction in demand for oil and gas, which resulted in a major downturn in commodity prices during 2020. COVID-19 and the related actions taken by governments and businesses to manage the pandemic, including voluntary and mandatory quarantines and restrictions on movement and travel, resulted in a significant and swift reduction in global economic activity. As a result of COVID-19, our operations, and those of both our local and global business partners, service companies and suppliers, experienced adverse effects, including, disruptions, delays or temporary suspensions of operations and supply chains, temporary inaccessibility or closures of facilities, and workforce impacts from illness, lack of availability (arising from domestic and/or international travel restrictions), school closures and other community response measures.

Any resurgence or outbreak of a contagious disease and resulting actions by governments and businesses to manage the spread of any disease could result in a recurrence of similar adverse conditions that characterized the COVID-19 pandemic, which may adversely affect our business, financial condition and result of operations.

Risks relating to our financial arrangements

We have debt, and may incur more debt in the future, which may adversely affect our business, financial condition and ability to pursue our growth objectives, and may impact our ability to repay our obligations, including under the Notes.

As of December 31, 2023, we had a total principal amount of US$274.1 million of debt outstanding and US$66.0 million of unavailable and unused commitments available under our RBL facility. Debt outstanding under the RBL facility will be effectively senior in right of payment to the Notes to the extent of the value of the Collateral securing the RBL facility. We expect to incur additional debt through the issuance of the Notes, although we intend to use a portion of the proceeds of this issuance to repay the RBL facility, which will then be available to be redrawn. As of December 31, 2023 on an as adjusted basis after giving effect to (i) the offering of Notes contemplated hereby, (ii) the repayment of our prior reserve-based, non-recourse, syndicated loan facility (which was repaid and canceled after December 31, 2023) and (iii) the repayment of the outstanding amount of the RBL facility as described under "Use of proceeds", the Notes will constitute our only substantial financial indebtedness. Subject to customary conditions to draw, US$246.0 million would be available immediately to be redrawn under the RBL facility, which indebtedness would be first-priority secured indebtedness and therefore effectively senior to the Notes. We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340.0 million committed under the RBL facility will become available, subject to customary conditions to draw. Under our existing debt instruments, including the indenture governing the Notes, we will be able to incur substantial additional indebtedness. Our debt level may increase significantly in the future, particularly if we incur additional debt to fund acquisitions.

Our debt levels may affect our business in the future, including by requiring us to devote a significant proportion of our cash flow from operations to servicing interest payments on our debt, reducing the cash available for other purposes, including working capital and capital expenditure to sustain our operations and invest in growth projects. High debt levels increase our vulnerability to adverse economic conditions, including a sustained downturn in oil and gas prices or significant cost increases. In these conditions, we may find it difficult to satisfy our obligations under our debt instruments, including the Notes, and we may be unable to refinance maturing debt. Our debt level may impair our ability to pursue opportunities to grow our business, including by limiting our ability to obtain additional financing. See also "—The covenants in our debt facilities, including the Notes, may limit our ability to finance our operations and pursue our growth plans."

If we are unable to raise funds on favorable terms, including in order to fund our growth projects and any future acquisitions and refinance our existing debt, our business could be adversely affected.

We rely on access to debt and equity financing to conduct our business, in particular, to fund our growth projects and any future acquisitions we may undertake, as well as to refinance our existing debt ahead of its maturity. There is a risk that we may not be able to access equity or debt capital markets to support our business objectives, or successfully refinance our current debt facilities on commercially favorable terms, or at all.

Our ability to secure financing (or financing on acceptable terms) may be adversely affected by volatility in the financial markets, a financial crisis, destabilizing events and disruption to the geopolitical environment and our industry or economic sector, or by a downgrade in our credit ratings. For example, in recent years, debt capital markets have been affected by volatility related to uncertainty about the impact of the COVID-19 pandemic and subsequently by sharp increases in interest rates as central banks sought to counter high inflation. In addition, over the past few years, certain financial institutions, institutional investors and other sources of capital have begun to limit or exit their investment in oil and gas activities citing concerns about climate change and ESG, which could make it more difficult and expensive to finance our business. For these or other reasons, financing may be unavailable to us or our cost of financing may be significantly increased. Such inability to obtain, or an increase in the costs of, financing could materially and adversely affect our business, results of operations and financial position. See "Management's discussion and analysis of financial condition and results of operation—Quantitative and qualitative disclosure around market risk—Interest rate risk" and "—Risks relating to the Notes and Security—Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly."

We seek to maintain sufficient liquid assets and available committed credit facilities to meet short-term and medium-term liquidity requirements. As of December 31, 2023, we had total available liquidity of US$170.4 million, all of which was cash and cash equivalents and outstanding borrowings of US$274.1 million, all of which was first-lien senior secured debt. As of December 31, 2023, we also had US$66.0 million undrawn under our RBL facility, all of which was committed but unavailable due to the borrowing base limit under our RBL facility, pending the addition of our interest in the Who Dat assets to the RBL facility borrowing base assets. See "Management's discussion and analysis of financial condition and results of operations—Liquidity and capital resources—Financing arrangements." If we fail to manage our liquidity position properly in the future, or if markets are not available to us at the time that we require any financing, there is a risk that our business and financial flexibility may be adversely affected.

We are exposed to foreign currency risk and foreign exchange regulations.

Our foreign exchange risk exposures primarily relate to our corporate overheads and business development expenditures, which are incurred in Australian dollars, and some of our operating and capital expenditures related to our Baúna production assets and the payment of Brazilian taxes, which are incurred in Brazilian real.

We generally do not hedge these exposures, but manage them from a liquidity perspective by forecasting our cash flows and ensuring that we hold sufficient Brazilian real and Australian dollar cash balances. However, these balances do not usually exceed the foreign currency amounts we estimate that we will need over the next three months.

Foreign exchange and foreign credit transactions in Brazil are subject to Central Bank regulations and specific legislation. Foreign credit transactions above certain thresholds are subject to reporting to the Central Bank. Exceptional and emergency cases related to a serious imbalance or an anticipated serious imbalance of Brazil's balance of payments may impose temporary restrictions on remittances of foreign capital abroad. Such restrictions may adversely affect the Bank's business, operations, or prospects and its ability to make foreign currency payments on its obligations outside Brazil.

We can give no assurances that we will successfully manage our exposure to exchange rate fluctuations and that exchange rate fluctuations or Brazilian foreign exchange regulations will not have a material adverse effect on our future financial position and performance.

The covenants in our debt facilities, including the Notes, may limit our ability to finance our operations and pursue our growth plans.

The indenture will restrict and the RBL facility restricts, among other things, our ability to:

- incur additional debt and issue guarantees and preferred stock;
- make certain payments, including dividends and other distributions, with respect to outstanding share capital;
- repay or redeem subordinated debt or share capital;
- create or incur certain liens;
- impose restrictions on the ability of our subsidiaries to pay dividends or make other payments to the Company and other subsidiaries;
- in the case of the RBL facility, make certain modifications to or terminations of our contractual arrangements, and exercise certain rights on operating or similar committees, with respect to our borrowing base assets;
- operate certain bank accounts relating to our borrowing base assets;

- make certain investments (including acquisitions and joint ventures) or loans and provide certain guarantees of performance obligations;

- sell, lease or transfer certain assets, including shares of any of our restricted subsidiaries;

- guarantee certain types of our other indebtedness without also guaranteeing the Notes;

- expand into unrelated businesses;

- merge or consolidate with other entities; and

- enter into certain transactions with affiliates

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

- limiting our ability to react to changes in market conditions, whether by increasing our vulnerability in relation to unfavorable economic conditions or by preventing us from profiting from an improvement in those conditions;

- affecting our ability to pursue business opportunities and activities that may be in our interest;

- limiting our ability to obtain certain additional financing in order to meet our working capital requirements, make investments or acquisitions and carry out refinancings; and

- requiring us to dedicate a significant portion of our cash flows to payment of the sums due for such loans, thus reducing our ability to utilize our cash flows for other purposes.

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

Risks relating to our regulatory, tax and legal environment

Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position.

Our business is subject to numerous laws and regulations in each of the jurisdictions in which we operate.

These relate to the exploration, appraisal, development, production, marketing, pricing, processing, refining, transportation and storage of our products, as well as the royalties, taxes and other imposts we must pay to applicable government authorities and landowners in connection with our activities. They also regulate how we conduct our business and operations, including our capacity to move capital between jurisdictions. A change in government and/or the laws, which apply to our business or the way in which we are regulated, could have a material adverse effect on our business, results of operations and financial position. For example, a change in taxation laws, environmental laws, health and safety laws, competition laws or the application of other existing laws or new laws, including any laws relating to climate change and/or greenhouse gas emissions, could also have a material effect on us. In addition, non-compliance with such laws and regulations, including non-compliance with our fundamental duties under laws and regulations applicable to corporations, labor, and competition and consumer legislation, could have an adverse effect on us and result in the assessment of administrative, civil or criminal penalties, issuance of remedial obligations and imposition of injunctions limiting or prohibiting certain of our operations. It is not uncommon for the governments of jurisdictions in which we operate to review the markets, laws, and regulations that impact our business from time to time, and this can lead to changes in the regulatory environment in which our joint venture partners or we operate.

In particular, the economic viability of our operations depends on the fiscal and regulatory regimes applicable to oil and gas operations in Brazil and the United States. See "Regulatory overview" for a summary of the principal features of these regimes that affect our business. Changes to these fiscal or regulatory regimes could increase our costs, require us to expend capital to keep our operations in compliance, increase our existing liabilities or create new liabilities, increase our royalty or tax obligations, any of which may have a material adverse effect on the profitability and viability of the affected operations.

We depend on exploration and production licenses that are conditional and may be subject to modification or withdrawal, and we may be unable to timely obtain, maintain or renew such licenses.

Our exploration for resources and our production of reserves depends on us being granted and maintaining appropriate licenses, permits, regulatory consents and authorizations. The process of obtaining licenses is long and intensive and often requires us to submit detailed plans that comply with regulatory requirements, prepare a large volume of supporting information and give a range of undertakings to regulators, including financial security. We may not be successful in obtaining, maintaining or renewing the licenses we need to pursue our business plans, including obtaining these in a timely manner, the granting of which may be subject to considerable discretion on the part of regulators and governments.

Once granted, licenses are usually subject to a range of conditions regarding the way we conduct our operations, including that we comply with applicable law. Exploration and development licenses often require us to spend minimum amounts of capital on our activities and reach milestones by certain dates, failing which our licenses may be canceled. Licenses may be subject to subsequent government action such as alteration, imposition of additional conditions or withdrawal, either pursuant to statutory discretions or otherwise. Such additional requirements may render a project economically unfeasible. Regulatory authorities may conduct announced and unannounced inspections of our operations. If we were to be found in noncompliance with one or more conditions of our licenses, we may be required to temporarily suspend our operations in part or in full, lose our licenses or be subject to civil, criminal or administrative liability, which could have a material impact on our operations and financial position.

Under Brazilian law, oil and gas activities are controlled and regulated by the Brazilian federal government, which grants, by means of a concession contract, a production sharing contract or a transfer of rights contract, the right to oil and gas exploration, development and production. All of our existing exploration and production rights are currently governed by concession contracts, which have been entered into with the ANP, whether directly (which is the case for the Neon, Goiá and Clorita fields) or through an assignment procedure with the ANP (which is the case for the Baúna field).

Under the terms of the Petroleum Law and concession contracts, these contracts may be subject to early termination in certain events, such as (i) failure to comply with the obligations established in the concession contracts, including, without limitation, failure to complete the minimum exploratory program, failure to timely submit the development plan to the ANP or failure to obtain ANP approval to the development plan; or (ii) bankruptcy of the party to the concession contract, in case if such party is unable to present a recovery plan duly approved that demonstrates to ANP the financial capacity to fulfill the contractual and regulatory obligations. In the case of early termination of the concession agreements, the conceded assets must be returned to the Brazilian federal government, and if the concessionaire has given cause to the early termination event, the concessionaire is not entitled to compensation, and may be subject to penalties.

The Brazilian federal government may also decide to unilaterally terminate the concession contracts or recover conceded assets by means of expropriation due to public interest, in which case the concessionaire is entitled to receive an indemnification. While there are no known instances of expropriation due to public interest in the past, if this were to occur, indemnity payments may not be sufficient to offset the investment we made.

The early termination of concession contracts will not release us from liability for losses and damages caused to third parties in connection with the concession granted, subject to the applicable statutory limitations and delay periods. Further, the early termination of concession contracts will not release us from obligations owed to our creditors.

In the event that a concession contract is terminated due to non-compliance with legal, regulatory or contractual provisions, any indemnity to be paid by the Brazilian federal government may be significantly reduced by the imposition of fines or other penalties.

In addition, in the case of early termination of present or future concession contracts, it is not possible to ensure that the amount of any indemnity will be sufficient to offset the investment made, the implied rate of return or the loss of future profit on assets not yet fully amortized. Concession contracts under which we are authorized to explore and produce oil and natural gas are subject to set expiration dates. Although we may want to extend concessions with the ANP beyond their original expiration dates, there is no assurance that the ANP would agree to such extension or, if ANP does so agree, that it would agree on terms that are acceptable to us, which may have a material adverse effect on our business, financial condition or results of operations. If the concession contracts are terminated, any assets, real property, equipment or facilities within the concession areas required for production or considered of public interest may revert to the ANP, without any additional compensation to us.

Several of our leases in the US Gulf of Mexico are subject to expiration within 2024 and 2025 unless drilling operations or production in paying quantities commences. In January 2024, LLOG has applied for unitization of leases in the Who Dat East field. The application is currently subject to regulatory review by the Bureau of Safety and Environmental Enforcement (“BSEE”). If successful, these leases or parts thereof would be combined with respective other existing leases that our joint venture holds by production and operated as a single unit with production or operations from one tract in the unit being treated as production or operations from every tract included in the unit. If one or more of our applications for unitization are not granted, we may be required to suspend our operations on the respective lease in part or in full or lose our licenses, which could have a material impact on our operations and financial position. See also “Business—Our concession agreements and leases.”

We can give no assurances that the licenses, permits, regulatory consents and authorizations will be renewed or granted or as to the terms of such renewals or grants. Moreover, if we do not meet our work and/or expenditure obligations under permits and licenses, this may lead to diminution of our interest in, or the loss of, such permits and licenses.

The costs of complying with environmental laws may increase, and we may incur substantial liabilities if an environmental incident occurs.

A range of environmental risks exist within oil and gas exploration, development and production activities. We operate in a number of highly environmentally sensitive areas. Environmental incidents and real or perceived threats to the environment or the amenity of communities could result in a loss of our social license to operate leading to delays, disruption to or the shutdown of current exploration and/or future production activities.

Our activities may result in environmental impacts, which may, in turn, give rise to substantial costs for environmental rehabilitation, damage control and losses. For example, we have been subject to fines by ANP in connection with the occurrence of oil sheen exceeding authorized levels at our operations in the Santos Basin from time to time. If we fail to manage our operational hazards and comply with environmental and safety requirements, such failure could lead to regulatory or environmental action, legal liability, material cost and reputational damage. Oil spills and leaks in the ocean can be particularly costly to remediate because of the propensity for damage to occur over a wide area and the environmental sensitivity of marine and coastal environments. Liability could be imposed on us without regard to our fault in the matter. For example, in the context of damages caused by oil spills and leaks both Brazilian and US rules provide for joint, several and strict civil liability under environmental laws.

With increasing government and public sensitivity to climate change and environmental sustainability, environmental regulation is becoming more stringent. We could be subject to increasing environmental responsibility and liability, including laws and regulations dealing with greenhouse gases and other air emissions, water, noise, losses of hydrocarbon and other discharges of materials into the environment, fauna and flora protection, the reclamation and restoration of our properties, and rehabilitation of the environment, hydraulic stimulation, the storage, treatment and disposal of wastes and the effects of our business on the marine environment. When we operate in new jurisdictions, we become subject to new regulations that may be more stringent or differ from those with which we have experience. Failure to manage these risks effectively could lead to concerns over the sustainability of our business.

Sanctions for non-compliance with these laws and regulations may include administrative, civil and criminal penalties, civil liability, revocation of licenses, permits, regulatory consents and authorizations, reputational issues, increased authorization conditions and corrective action orders. These laws sometimes apply retroactively. In addition, a party can be liable for environmental damage without regard to that party's negligence or fault.

Increased costs associated with regulatory compliance and/or with litigation could have a material and adverse effect on our earnings and cash flows. Increased environmental activism, including in the form of activist shareholder campaigns, also presents potential increased costs and reputational risks, including time spent by management with respect to managing and responding to governments, regulators, investors and activists.

Additional drilling laws, regulations, executive orders and other regulatory initiatives that restrict, delay or prohibit oil and natural gas exploration, development and production activities or access to locations where such activities may occur could have a material adverse effect on our business, financial condition or results of operations.

Our operations may become subject to additional drilling laws, regulations, executive orders or other regulatory initiatives limiting oil and natural gas exploration, development or production. For example, the US administration has recently taken a number of actions that may result in stricter environmental, health and safety standards applicable to our operations in the US Gulf of Mexico.

In January 2021, President Biden issued an executive order suspending new leasing activities for oil and natural gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and natural gas permitting and leasing practices. After a group of states challenged the executive order, a federal judge required the U.S. Department of Interior (the "DOI") to stop the leasing pause. These lease sales are conducted pursuant to five-year leasing programs under the Outer Continental Shelf Lands Act. In September 2023, consistent with the requirements of the U.S. Inflation Reduction Act (the "IRA") concerning offshore conventional and renewable energy leasing, the DOI announced its proposed 2024-2029 National Outer Continental Shelf Oil and Gas Leasing Program (an "OCS Program"). The proposed OCS Program includes a maximum of three potential oil and natural gas lease sales in the Gulf of Mexico scheduled in 2025, 2027 and 2029. This is the fewest number of lease sales in the program's history and the minimum amount needed to continue expanding an offshore wind program under the IRA, which does not allow offshore wind leases unless enough oil and gas leases are offered the year before. Moreover, it is likely that the new five-year leasing program will be subject to heightened environmental review. It is also possible that the program could be delayed by opposing lawsuits that were filed on February 12, 2024 by the American Petroleum Institute and by Earthjustice representing multiple environmental groups both of which are challenging the Bureau of Ocean Energy Management's ("BOEM's") actions. Future actions taken by the Biden Administration to limit the availability of new oil and gas leases on the Outer Continental Shelf ("OCS") would adversely impact the offshore oil and gas industry and impact demand for our products.

In addition, over the past decade, BSEE and BOEM have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in United States federal waters. For example, in August 2023, BSEE published a final rule, effective October 23, 2023, to clarify and modify certain blowout preventer system requirements. The rule requires, among other things, that the blowout preventer system is able to close and seal the wellbore at all times to the well's maximum kick tolerance design limits and includes more stringent requirements for failure reporting.

Compliance with any added or more stringent regulatory requirements in the United States or Brazil or enforcement initiatives and existing environmental and spill regulations, together with uncertainties or inconsistencies in decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development, oil spill response and decommissioning plans could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts.

These regulatory actions, or any new laws, executive orders, regulations or other legal or enforcement initiatives, that impose increased costs or more stringent operational standards could delay or disrupt our operations, result in increased supplemental bonding and associated costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in suspension or cancellation of leases. Also, if material spill incidents were to occur in the future, the United States, Brazil or other countries where such an event may occur could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which could have a material adverse effect on our business. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling and production operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations. See "—Risks relating to our industry and operations—Our insurance arrangements may be inadequate to cover losses arising from our operations."

We are exposed to political risk in Brazil and the United States.

Our interests in Brazil and the United States are subject to political, economic, social and other uncertainties, including the risk of expropriation, nationalization, renegotiation or termination of existing contracts, licenses and permits or other agreements, changes in laws or taxation policies, currency exchange restrictions and changing political conditions, insurrection, acts of terrorism, civil rebellion, border and territorial disputes and war. Both Brazil and the United States have been subject to political instability, including violent protests against election results, and the immediate past president of each country is currently awaiting trial on criminal charges relating to their conduct in office.

Political instability could result in more volatile or extreme policy-making, undermine confidence in government processes and the rule of law or result in civil unrest. A more volatile political environment may increase the risk of governments taking actions that adversely affect our business, such as expropriation or nationalization, without appropriate processes or compensation. Political instability could undermine investor confidence in the affected jurisdiction, resulting in a redirection of capital, reducing the value of our assets and making it more difficult for us to refinance our debt or obtain new finance.

The effects of these factors are difficult to predict and any combination the above may have a material adverse effect on the operation or development of our business and/or the ownership or control of our assets.

The Brazilian government exercises significant influence over the Brazilian economy. This influence, as well as Brazilian political and economic conditions, may materially and adversely affect us.

The Brazilian government has frequently intervened in the Brazilian economy and has occasionally made significant changes in policy and regulations, influencing the Brazilian economy. The Brazilian government's actions to control inflation and the implementation of policies and regulations have often involved, among other measures, interventions in interest rates and in the foreign exchange market, changes in tax policies, price controls, capital controls and limits on imports. We cannot control or predict which measures or policies will be adopted by the Brazilian government in the future. We may be materially and adversely affected by changes in policies or regulations involving or affecting factors, including:

- oil and gas prices in Brazil and abroad;
- interest rates;
- foreign exchange controls and restrictions on remittances abroad;
- exchange rate fluctuations;
- changes in labor and regulatory rules;
- tax policies and changes in tax laws;
- import and export controls;
- increased unemployment;
- economic, social and political instability; and
- other political, diplomatic, social, environmental, climate and economic developments in or affecting Brazil.

We are subject to, and may become liable for any violations of anti-corruption, anti-bribery, anti-money laundering, sanctions and similar laws.

We are subject to anti-corruption, anti-bribery and anti-money laundering, sanctions and similar laws and regulations in the jurisdictions in which we operate and the jurisdictions whose laws govern our financial arrangements. These laws include the U.S. Foreign Corrupt Practices Act, the Brazilian Clean Companies Act (Law No. 12,846/2013), the Australian Autonomous Sanctions Act 2011 (Cth), the Anti-Money Laundering and Counter-Terrorism Financing Act 2006 (Cth), the Charter of United Nations Act 1945 (Cth) and the Australia Criminal Code Act 1995 (Cth) and generally prohibit companies, their agents, their contractors and company employees from engaging in bribery or other prohibited payments to government officials, directly or indirectly, for the purpose of obtaining or retaining business, implement restrictions on certain business relationships and require companies to maintain accurate books and records and internal controls. In the future, we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations or private entities. Thus, we face the risk of unauthorized payments or offers of payment by one of our employees, joint venture partners, consultants or third-party agents, given these parties may not always be subject to our control.

We deal with a broad range of counterparties on a regular basis through our business relationships and contracts. Given the nature of our operations and activities, we are, in particular, exposed to the risk of violations of anti-corruption and anti-bribery laws in connection with our operational, marketing, trading and procurement activities in Brazil. Brazil was ranked 104th out of 180 countries and territories in Transparency International's 2023 Corruption Perception Index, which lists countries according to their perceived levels of corruption, as determined by expert assessments and opinion surveys. Numerous members of the Brazilian government and of the legislative branch, as well as senior officers of large state-owned and private companies have been convicted of political corruption due to officials accepting bribes by means of kickbacks on contracts granted by the government to several infrastructure, oil and gas, and construction companies, among others.

A company may be found liable for violations by not only its employees but also by its contractors and third-party agents. Our internal procedures and policies may not always be effective in ensuring that our employees, contractors, third-party agents or we will comply strictly with all such applicable laws. If we become subject to an enforcement action or we are found to be in violation of such laws, this may have a material adverse effect on our reputation and may possibly result in significant penalties or sanctions and may have a material adverse effect on our business, financial condition or results of operations.

Laws regulating greenhouse gas emissions could adversely affect the cost, manner and feasibility of doing business and demand for the oil and gas that we produce.

Our operations and properties generate greenhouse gas emissions and hydrocarbons, which contribute to climate change. A number of governments and governmental bodies, including those in Australia, Brazil and the United States have introduced laws and regulations to reduce greenhouse gas emissions, and they may expand these laws and regulations in the future. These laws have increased and may continue to increase our operating and compliance costs. There remains significant uncertainty regarding the future of climate change regulation and the effect it may have on our business, although the social and governmental focus on climate change is likely to result in further regulation of industries and companies that generate greenhouse gas emissions.

In addition, there have been a number of legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of climate change, including greenhouse gas emissions, and to respond to commitments under international agreements, such as the 2016 Paris Agreement on climate change. See "—Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position."

Future legislation or regulation mandating reductions in greenhouse gas emissions could have far-reaching and significant impacts on our operations and on the energy industry. We anticipate that our activities will be subject to increasing regulation and costs associated with climate change and the management of greenhouse gas emissions, including through the increased risk of investigations and litigation pursuant to any related legislation or regulation. Such regulations could result in increased costs to operate our facilities or additional operating restrictions on our business, capital expenditures to install new emission controls at our facilities, and costs to administer and manage any potential greenhouse gas emissions or carbon-trading or tax programs, which may rely on our ability to obtain sufficient carbon offset credits at a commercially reasonable price.

These potential further regulations and initiatives could also restrict or impose additional cost on fossil fuel use and promote energy efficiency and lower emission energy sources. This may reduce demand for our products and could reduce the prices that we receive, thereby reducing our revenues and adversely impacting our earnings, reserves and resources. Effective stakeholder opposition, non-governmental activism and interest groups lobbying for increased climate change regulation also have the potential to delay project schedules and the production of oil, gas or both, and may also increase the costs of project execution.

Our provisions for future removal and environmental restoration costs may underestimate our future costs, which could result in impairment charges or higher costs than we anticipate.

Our oil and gas operations are subject to laws and regulations that require us to close and restore our wells, pipelines, facilities and other assets after they cease to produce or are no longer economically viable. At that point, we will incur substantial costs for, among other things, removing facilities and decommissioning wells and restoring the affected areas. We recognize accounting provisions reflecting our best estimate of the present value of the future expenditure required to settle the restoration obligation at the reporting date, based on current legal requirements or observed industry analogues. We update our restoration provisions regularly, and adjustments in our estimates are reflected in the present value of the restoration provision at the reporting date, with a corresponding change in the cost of the associated asset.

As discussed in more detail under "Management's discussion and analysis of financial condition and results of operations—Critical accounting policies—Provision for restoration" and Note 16 to our TY23 audited financial statements, we record accounting provisions for the estimated present value of our future closure and restoration obligations based on our best estimates of the timing and amount of the expenditures. However, these estimates are subject to significant uncertainties and may change over time due to various factors, such as changes in laws and regulations, environmental conditions, operating plans, asset performance, inflation, discount rates, and technological developments. For example, because we own assets in the US Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes and other adverse weather conditions. The estimated costs to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Also, a sustained lower commodity price environment may cause our joint venture partners to be unable to pay their share of costs, which may require us to pay our proportionate share of the defaulting party's share of costs.

As a result, our actual closure and restoration costs and liabilities may differ materially from our accounting provisions, and we may incur additional charges or adjustments to our financial statements in the future. Any such charges or adjustments could have a material adverse effect on our financial condition and results of operations.

In September 2023, we provided a surety bond in the amount of US$98.2 million (as of December 31, 2023) to ANP in connection with existing decommissioning obligations relating to the Baúna field in Brazil. This surety bond replaced and topped up a company guarantee we provided previously. As of the date of this offering memorandum, we continue to await regulatory approval from ANP. In connection with the acquisition of our US Gulf of Mexico assets, we acceded into several decommissioning security agreements with the BOEM and expect to make financial contributions under these agreements from 2030 onwards.

The surety bond was provided in connection with the obligation set forth in ANP Resolution No. 854/2021, which regulates the procedures for provision of financial guarantees and terms to secure the financial resources for the decommissioning of production facilities in oil and natural gas fields, based on the adoption of progressive contributions. In addition, such resolution establishes the guarantees accepted by the ANP, namely letters of credit, corporate collaterals, provisioning funds, oil and natural gas pledge, performance bonds or the execution of extrajudicially enforceable instruments. In order to be approved by ANP, the guarantees submitted must follow the requirements provided under ANP Resolution No. 854/21. ANP may order the replacement of the adopted guarantee at any time, including whenever a technical study shows that the provided guarantee is insufficient or inadequate. If we fail provide the guarantee for the decommissioning in assignment proceedings pending with the ANP, the assignment will not be completed, as the guarantee is a requirement set forth in ANP Resolution No. 854/21. If we fail to renew the decommissioning guarantees, the guarantee originally provided may be foreclosed by ANP, pursuant to ANP Resolution No. 854/21, and we may be subject to the penalties set forth in Law No. 9,847/1999 for non-compliance with requirements set forth in applicable law and in ANP Resolutions. For further information, please see "Regulatory overview—Decommissioning" and "Regulatory overview—Regulatory overview—Brazil—Decommissioning."

In the United States, the BOEM currently requires all lessees of an OCS oil and natural gas lease to post base bonds ranging from US$50,000 to US$3.0 million in addition to supplemental financial assurance determined based on the lessee's ability to carry out present and future financial obligations. In June 2023, the BOEM proposed a new rule that updated the criteria for determining whether oil and natural gas lessees may be required to provide supplemental financial assurance to ensure compliance with the Outer Continental Shelf Lands Act. A final rule was published on April 15, 2024 and we are considering its impact on our operations. If our joint venture becomes subject to significantly higher bonding obligations, we may be required to pay additional costs and experience an adverse impact on our financial position. Moreover, the implementation of the new rule could result in sureties seeking additional collateral to support existing or future bonds, such as cash or letters of credit, and we cannot provide assurance that our joint venture will be able to satisfy collateral demands for such bonds to comply with supplemental bonding requirements of BOEM. If we are required to provide collateral in the form of cash or letters of credit, our liquidity position could be negatively impacted, and we may be required to seek alternative financing. These and other changes to BOEM bonding and financial assurance requirements could result in increased costs on our operations, reduced cash flows if unable to comply and consequently have a material adverse effect on our business and results of operations.

Our business exposes us to potential tax liabilities that could have an adverse impact on our results of operations.

In addition to the standard level of income tax imposed on all industries, as a company in the petroleum and gas industry, we are required to pay additional taxes in the form of government royalties on petroleum production, direct and indirect taxes and other imposts in the jurisdictions in which we operate. See "Business—Brazil—Producing asset—Báuna—Licensing and royalties" and "Business—US Gulf of Mexico—Producing asset—Who Dat—Licensing and royalties" for more detail on the tax and royalty regimes to which our operations are subject. Our after-tax profitability could be affected by numerous factors, including the availability of tax credits, exemptions, refunds (including refunds of value added taxes) and other benefits to reduce our tax liabilities, changes in the relative amount of our earnings subject to tax in the various jurisdictions in which we operate or have subsidiaries, the potential expansion of our business into or otherwise becoming subject to tax in additional jurisdictions, changes to our existing business structure and operations, the extent of our intercompany transactions and the extent to which taxing authorities in the relevant jurisdictions respect those intercompany transactions.

From time to time, federal and state level legislation in the United States has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently available to oil and natural gas exploration and development companies. Such proposed legislative changes have included, (i) the elimination of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) an extension of the amortization period for certain geological and geophysical expenditures, (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies and (v) an increase in the U.S. federal income tax rate applicable to corporations (such as us). U.S. states in which we operate or own assets may also impose new or increased taxes or fees on oil and natural gas extraction. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Future tax legislative or regulatory changes in the United States, Brazil or in any other jurisdictions in which we operate now or in the future could also adversely impact our after-tax profitability.

Additionally, these tax regimes can be subject to differing interpretations and tax rules in any jurisdiction are subject to legislative change and changes in administrative and regulatory interpretation. Our interpretation of applicable tax law may not coincide with that of the relevant tax authorities. As a result, transactions may be challenged by tax authorities and any of our profits from activities in those jurisdictions in which we operate may be subject to additional tax or additional unexpected transactional taxes (e.g., stamp duty, VAT or capital gains tax), which, in each case, could result in significant legal proceedings and additional taxes, penalties and interest, any of which could have a material adverse effect on our business, prospects, financial condition and results of operations. In addition, taxing authorities could review and question our tax returns leading to additional taxes and penalties, which could be material. Currently, there are also different bills under discussion in the Brazilian Congress that seek to implement tax reforms, including proposals to modify the taxation applicable to legal entities. See "—There are several tax reforms under consideration in Brazil, which may adversely impact our tax obligations."

We seek to maintain a constructive and transparent relationship with taxation revenue authorities in each jurisdiction in which we operate. From time to time, we may disagree with taxation authorities on the interpretation of taxation laws. Where such differences meet the necessary criteria, they will be reflected in our financial statements accordingly. Our financial position and results of operations may be negatively impacted should a relevant authority disagree with a tax position we have adopted and we are ultimately unsuccessful in maintaining that position through various avenues of appeal (including a court appeal).

There are several tax reforms under consideration in Brazil, which may adversely impact our tax obligations.

Currently, there are different bills under discussion in the Brazilian Congress that seek to implement tax reforms, including proposals to modify the taxation applicable to legal entities.

On November 20, 2023, Constitutional Amendment No. 132 was approved, which instituted the consumption tax reform, amending the Brazilian tax system. Among the main changes brought about by the Constitutional Amendment No. 132/2023 is the unification of certain taxes: (a) Tax on Services and Tax on the Circulation of Goods and Services are unified in the form of the Tax on Goods and Services, and (b) Contributions to the Social Integration Program and to the Social Security Financing and Tax on Industrialized Products are replaced by the Contribution on Goods and Services. The new system will be implemented over a period of seven years, from 2027 to 2033. However, regulations with respect to the modifications have yet to be finalized (i.e., the definition of applicable rates). We are closely monitoring the developments as they may impact our tax burden.

With regard to income taxation, the Brazilian government has been discussing possible changes in corporate tax rates as a way to balance the impact of a possible taxation of dividends, as well as other changes that may impact the tax burden applicable to legal entities. In recent years, the Brazilian government has presented some proposals to the Brazilian Congress related to the taxation of dividends and the prohibition of the deduction of interest on equity, among which are currently in progress: (i) Bill No. 2,337, dated June 25, 2021, which provides for changes in income taxation, such as the introduction of the taxation of dividends and the repeal of the deduction of interest on equity; (ii) Bill No. 4,258, dated August 31, 2023, which prohibits the deduction of interest on equity from the calculation basis of Corporate Income Tax and Social Contribution on Net Income; and (iii) Bill No. 4,921, of October 10, 2023, which provides for the levying of Withholding Income Tax on profits and dividends paid, credited, delivered, employed or remitted to beneficiaries, individuals or legal entities, resident or domiciled abroad.

Bills No. 4,258/2023 and No. 4,921/2023, recently presented, are in the initial stages of processing before the Chamber of Deputies and the Brazilian Senate, respectively. In turn, Bill No. 2,337/2021 was approved by the Chamber of Deputies on September 2, 2021 and is currently awaiting consideration by the Brazilian Senate. The proposal was evaluated by the Committees, and since April 19, 2023, it has been with the rapporteur of the legislative house. The approval of these bills depends on the legislative process, which includes evaluation, voting, vetoing and amendments, all carried out by the Brazilian Congress and the President of the Republic. It is not possible to determine, from the outset, which proposals will be effectively implemented and how they may impact our operations.

In addition, on December 15, 2023, the house of representatives also approved the bill to convert Provisional Measure No. 1,185/2023 into the Law No. 14,789/2023, which establishes a new system for the tax treatment of revenues arising from governmental subsidies at the federal level.

Moreover, Law No. 14,789/23 changed the tax system for the deduction of expenses with the payment of interest on net equity, by altering certain aspects of the formula for calculating such expenses and making it more restrictive than the previous rules. Law No. 14,789/2023 came into force as of January 1, 2024, bringing a relevant impact to taxpayers who benefit from subsidies for investment and funding.

The Brazilian tax authorities have frequently implemented changes to tax regimes that may affect us and ultimately the demand of our customers for the products we sell. These measures include changes in prevailing tax rates and enactment of taxes, both temporary and permanent. Some of these changes may increase our tax burden, which may increase the prices we charge for the products we sell, restrict our ability to do business in our existing markets and, therefore, materially adversely affect our results of operations. There can be no assurance that we will be able to maintain our projected cash flow and results of operations following any increases in Brazilian taxes that apply to us and our operations.

In addition, we currently receive certain tax benefits. There can be no assurance that these benefits will be maintained or renewed. Also, given the current Brazilian political and economic environment, there can be no assurance that the tax benefits we receive will not be judicially challenged as unconstitutional. If we are unable to renew our tax benefits, such benefits may be modified, limited, suspended, or revoked, which may adversely affect us. Moreover, certain tax laws may be subject to controversial interpretation by tax authorities. In the event that tax authorities interpret tax laws in a manner that is inconsistent with our interpretations, we may be adversely affected.

On December 21, 2023, the Brazilian House of Representatives approved a bill to create a Brazilian Greenhouse Gas Emissions Trading System. Subject to the approval of the bill by both houses of the Brazilian parliament, Karoon, which has facilities or sources that may emit greater than 10,000 tCO_2/e per year, is likely to be considered a regulated entity under the scope of the regulation, which may impose reporting and other requirements on us. Under the currently proposed rules, we would be required to acquire assets, which are also known as SBCE assets, through the trading system. These assets include Brazilian Emissions Quotas, which are similar to the European Union Emissions Trading System, and Verified Emission Reduction Certificates. A portion (which is not yet defined) of the Verified Emission Reduction Certificates could be originated from voluntary carbon credits that meet certain legal requirements. However, the implementation and timeline for a Brazilian carbon market remains uncertain. Moreover, the Brazilian government may adopt new or more stringent measures to address climate change and greenhouse gas emissions in the future, which could increase our costs, liabilities, or obligations, or restrict our ability to operate or expand our assets. See also "—Laws regulating greenhouse gas emissions could adversely affect the cost, manner and feasibility of doing business and demand for the oil and gas that we produce" and "Regulatory overview—Regulatory overview-Brazil—Carbon credits and the Brazilian Greenhouse Gas Emissions Trading System."

Furthermore, the Brazilian Chamber of Deputies is currently discussing Bill No. 182, of 2024, which, among other things, intends to regulate the federal taxation of carbon credits. According to the Bill, the gain arising from the sale of these assets will be subject to income tax in accordance with: (i) the tax regime applicable to the taxpayer, in the case of developers who initially issued such assets (i.e., the issuer), (ii) the taxation applicable to net gains, when earned in transactions carried out on stock, commodity and futures exchanges and in organized over-the-counter markets (i.e., trading), and (iii) the taxation applicable to capital gains, in other cases. Bill No. 182/2024 is still in the initial processing phase, so it is not possible to affirm whether such provisions will make up the final wording of the bill or if it will be approved by both houses of the Brazilian parliament.

Our business subjects us to potential liability from litigation, arbitration and regulatory action.

The nature of our operations subjects us to the risk of litigation and/or regulatory action based on alleged violations of law, particularly environmental protection and health and safety laws. We are party to a wide range of joint venture, commercial agreements, including agreements with critical third-party infrastructure providers, and other relationships, which may also lead to disputes that result in litigation or arbitration claims. As a listed company, we also face the risk of shareholder class actions relating to the adequacy of our disclosures.

Damages claimed under any litigation, arbitration, regulatory action, including shareholder class actions, may be material or may be indeterminate, and the outcome of such litigation, arbitration or regulatory action could materially and adversely affect our business, results of operations or financial position. Preparing for and participating in litigation, arbitration or regulatory proceedings may occupy significant management time and distract management from their focus on our business. While we assess the merits of each lawsuit and defend ourselves accordingly, we may be required to incur significant expenses in defending against any such lawsuit and there can be no assurance that a court or tribunal will find in our favor. In addition, proceedings in which we are not directly subject may impact our business and operations.

We may also be involved in investigations, inquiries or disputes, debt recoveries, native title claims, pre-emptive right disputes, land tenure and access disputes, contractual claims with respect to our activities (including with suppliers, customers, joint venturers and parties engaged to construct and or develop our projects and infrastructure), environmental claims or occupational health and safety claims. Any of these claims or actions could result in delays, increase costs or otherwise adversely impact our assets and operations, financial performance and future financial prospects.

Similarly, one or more of our officers and directors may be defendants in judicial, administrative and/or arbitral proceedings, in civil, environmental, criminal, tax and/or labor matters. The commencement and/or the results of these proceedings may adversely affect our directors and officers, especially in cases of criminal proceedings, which may prevent them from exercising their corporate functions appropriately, causing adverse effects to our reputation, business or results of operations.

Our business, practices and policies are subject to risks associated with non-compliance with the Brazilian General Data Protection Law and could be adversely affected by the application of penalties, including fines and indemnifications.

Law No. 13,709/18, as amended by Law No. 13,853/2019, or the Brazilian General Data Protection Law, or LGPD, governs the processing of personal data in all economic sectors, and prescribes the rights of the data subjects, the legal bases applicable to the processing of personal data, the requirements for obtaining consent, the obligations and requirements relating to security incidents, breaches and data transfers, as well as authorization for the creation of the National Data Protection Authority, or ANPD, the government agency responsible for ensuring compliance with data protection standards and for applying sanctions in case of breach of the LGPD or security incidents.

If the measures we implement are considered insufficient by the ANPD to protect the personal data that we process or to maintain compliance with any requirement established by the LGPD, we may be subject to: (i) fines of up to 2% of the turnover of the legal entity or group in Brazil, limited to R$50 million (approximately US$10.3 million) per infraction, or other administrative penalties, (ii) obligations to repair damages to data subjects, clients or other business partners or providers and/or (iii) reputational damages, which could adversely affect our results of operations.

As the ANPD continues to release guidance on the implementation of LGPD obligations, the legal framework will evolve, and best practice examples will continue to emerge. In the event we are not in compliance with the LGPD, we and our subsidiaries may be subject to certain sanctions and we may be liable for material, moral, individual or collective damages, which could materially and adversely affect us. For further information, see "Regulatory overview—Regulatory overview—Brazil—Data protection and the Brazilian General Data Protection Law."

Risks Related to the Notes and Security

Our ability to generate cash depends on many factors beyond our control and we may not be able to generate sufficient cash to service all of our indebtedness, including the Notes, and to fund our working capital and capital expenditures, and may be forced to take other actions to satisfy our obligations under our indebtedness that may not be successful.

Our ability to pay principal and interest on the Notes and to satisfy our other debt obligations will depend upon, among other things:

- our future financial and operating performance (including the realization of any cost savings described herein), which will be affected by prevailing economic, industry and competitive conditions and financial, business, legislative, regulatory and other factors, many of which are beyond our control;

- our future ability to refinance or restructure our existing debt obligations, which depends on, among other things, the condition of the capital markets, our financial condition, and the terms of existing or future debt agreements; and

- our future ability to borrow under the RBL facility, the availability of which depends on, among other things, our complying with the covenants in the credit agreement governing such facility.

This will be affected by our ability to successfully implement our business strategy, as well as general economic, financial, competitive, regulatory and other factors beyond our control. We can provide no assurance that our business will generate cash flow from operations, or that we will be able to draw under the RBL facility or otherwise, in an amount sufficient to fund our liquidity needs, including the payment of principal and interest on the Notes.

If our cash flows and capital resources are insufficient to service our indebtedness, we may be forced to reduce or delay capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness, including the Notes. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of existing or future debt agreements, including the instruments governing the RBL facility, may restrict us from adopting some of these alternatives. In the absence of such operating results and resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. We may not be able to consummate those dispositions for fair market value or at all. Furthermore, any proceeds that we could realize from any such dispositions may not be adequate to meet our debt service obligations then due. Our inability to generate sufficient cash flow to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, could result in a material adverse effect on our business, financial condition and results of operations and could negatively impact our ability to satisfy our obligations under the Notes.

If we cannot make scheduled payments on our indebtedness, we will be in default and lenders under the RBL facility could declare all outstanding principal and interest to be due and payable, the lenders under the RBL facility could terminate their commitments to loan money, our secured lenders could foreclose against the assets securing the indebtedness owing to them, and we could be forced into bankruptcy or liquidation. All of these events could cause you to lose all or part of your investment in the Notes.

If our indebtedness is accelerated, we may need to repay or refinance all or a portion of our indebtedness, including the Notes, before maturity. There can be no assurance that we will be able to obtain sufficient funds to enable us to repay or refinance our debt obligations on commercially reasonable terms, or at all.

If we default on our obligations to pay our other indebtedness, we may not be able to make payments on the Notes.

Any default under the agreements governing our indebtedness that are not waived by the required lenders and the remedies sought by the lenders of such indebtedness could leave us unable to pay principal, premium, if any, or interest on the Notes and could substantially decrease the market value of the Notes. In addition, the occurrence or continuance of any such default may result in us being prevented from undertaking transactions, exercising rights, or making payments, that would, in each case, be permitted in the absence of a default. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, or interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness (including the RBL facility), we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to, among other things, (i) declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, (ii) demand cash cover in connection with contingent exposures, (iii) terminate their commitments and cease making further loans and (iv) institute foreclosure or other enforcement proceedings against our assets, and we could be forced into bankruptcy or liquidation. Further, any foreclosure or other enforcement proceedings against our assets could breach the terms of our contracts or trigger changes of control, termination rights or other rights or remedies of our counterparties under our contracts, which may further materially and adversely affect our financial position and results of operation and our ability to satisfy our obligations under the Notes. See also "—It may be difficult to realize the value of the Collateral securing the Notes, which may result in holder of the Notes not receiving full payment of the obligations owed under the Notes following an event of default."

If our operating performance declines, we may in the future need to seek waivers from the required lenders under the RBL facility to avoid being in default. If we breach our covenants under the documents governing our indebtedness and seek a waiver, we may not be able to obtain a waiver from the required lenders, as applicable. If this occurs, we would be in default under the documents governing our indebtedness, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation. See "Description of other financing arrangements" and "Description of the Notes."

The Issuer is a finance subsidiary of the Parent Guarantor that has no revenue generating operations of its own and will depend on cash from Karoon Energy to be able to make payments on the Notes.

The Issuer is a finance subsidiary of the Parent Guarantor with no business operations or subsidiaries and has limited assets and a limited ability to generate revenues. Following the offering of the Notes and the use of proceeds therefrom as described under "Use of proceeds," the Issuer's material liabilities will be the Notes. The Issuer will be dependent upon receiving funds from the Parent Guarantor and its other subsidiaries to meet its obligations, including its obligations under the Notes. If the Parent Guarantor's subsidiaries do not distribute cash to the Issuer to make scheduled payments on the Notes, the Issuer may not have any other source of funds that would allow it to make payments to holders of the Notes. The amounts available to the Issuer will depend on the profitability and cash flow of Karoon Energy. No assurance can be given that our Subsidiary Guarantors' cash flow from operations will be sufficient to fund the Issuer's repayment of the Notes.

Our subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of our indebtedness, including the Notes. Each of our subsidiaries is a distinct legal entity, and under certain circumstances legal and contractual restrictions (including the terms of the RBL facility) may limit our ability to obtain cash from them and we may be limited in our ability to cause any future joint ventures to distribute their earnings to us. In particular, distributions by Borrowing Base Obligors must be set out in the most recent liquidity statement delivered by us from time to time under the RBL facility. See "Description of other financing arrangements." Further, if the proportion of the borrowing base limit under the RBL facility attributable to development assets exceeds 35% of the total borrowing base limit, any such distribution by Borrowing Base Obligors is subject to approval of the majority lenders under the RBL facility. Applicable tax laws may also subject such payments to further taxation. While the indenture that will govern the Notes will limit the ability of our subsidiaries to incur consensual restrictions on their ability to pay dividends or make other intercompany payments to us, these limitations will not apply to existing restrictions and are subject to certain qualifications and exceptions. In the event that the Issuer and the Guarantors do not receive distributions from our subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the Notes.

No assurance can be given that our subsidiaries' cash flow from operations will be sufficient to fund the Issuer's repayment of the Notes or the Guarantors' obligations under the Guarantees. In the event of an adverse change in the financial condition or cash flow generation of our subsidiaries, the Issuer and the Guarantors may not have sufficient funds to repay all amounts due on or with respect to the Notes, which would materially and adversely affect our financial position and results of operation and our ability to satisfy our obligations under the Notes.

The Notes will be structurally subordinated to all liabilities of our current and future non-Subsidiary Guarantor subsidiaries and junior to any of our future secured obligations that are secured by assets not constituting Collateral, to the extent of the value of the collateral securing such obligations.

The Notes will be structurally subordinated to indebtedness and other liabilities of our current and future subsidiaries that are not or will not be guaranteeing the Notes, and the claims of creditors of these subsidiaries, including trade creditors, will have priority as to the assets of these subsidiaries. In the event of a bankruptcy, liquidation or reorganization of any of our non-Subsidiary Guarantor subsidiaries, these non-Subsidiary Guarantor subsidiaries will pay the holders of their debts, holders of preferred equity interests and their trade creditors before they will be able to distribute any of their assets to us. The subsidiaries of the Parent Guarantor that will not guarantee the Notes on issuance have substantially no outstanding indebtedness, assets, liabilities, revenues or profits.

In addition, the indenture will permit non-Subsidiary Guarantor subsidiaries to incur additional indebtedness and will not contain any limitation on the amount of other liabilities, such as trade payables, that may be incurred by these subsidiaries.

The Notes will not be guaranteed by any of our subsidiaries that are not material or wholly owned. These non-Subsidiary Guarantor subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay any amounts due pursuant to the Notes, or to make any funds available therefore, whether by dividends, loans, distributions or other payments. Any right that we or the Subsidiary Guarantors have to receive any assets of any of the non-Subsidiary Guarantor subsidiaries upon the liquidation or reorganization of those subsidiaries, and the consequent rights of holders of Notes to realize proceeds from the sale of any of those subsidiaries' assets, will be effectively subordinated to the claims of those subsidiaries' creditors, including trade creditors and holders of preferred equity interests of those subsidiaries.

Our obligations with respect to the Notes will be effectively junior to any of our future secured obligations with a security interest on assets not constituting Collateral, in each case, to the extent of the value of the collateral securing such obligations. Accordingly, the holders of the Notes may not be able to realize proceeds from assets not constituting Collateral.

If we classify subsidiaries as Unrestricted Subsidiaries, they will not be subject to any of the covenants in the indenture, and we may not be able to rely on the cash flow or assets of our Unrestricted Subsidiaries to pay the Notes or our other indebtedness.

While we currently have not designated any of our subsidiaries as Unrestricted Subsidiaries, we may classify certain of our wholly-owned subsidiaries as Unrestricted Subsidiaries in the future. Unrestricted Subsidiaries may not be subject to the covenants under the indenture. Unrestricted Subsidiaries may enter into financing arrangements that limit their ability to make loans or other payments to fund payments in respect of the Notes. Accordingly, we may not be able to rely on the cash flow or assets of our Unrestricted Subsidiaries to pay the Notes or any of our other indebtedness. In addition, the indenture will permit us to make significant investments in Unrestricted Subsidiaries.

Each Guarantor's liability under its Guarantee may be reduced to zero, avoided or released under certain circumstances, in which case you may not receive any payments from some or all of the Guarantors.

The creation and perfection of the security interests in respect of certain Collateral are governed by Australian, Brazilian, English and New York law. The laws relating to the creation and perfection of security interests in such non-U.S. jurisdictions differ from those in the United States and may be subject to restrictions and limitations, the effect of fraudulent conveyance and similar laws. These restrictions and limitations may have the effect of preventing, limiting and/or delaying the foreclosure and subsequent disposition of such Collateral, or reducing (including to zero) the amount recoverable thereunder, and may materially impair the claims of noteholders. Any such delay in having an enforceable claim could also diminish the value of the interest of the Noteholders in the Collateral due to, among other things, the existence of other potential creditors and claimants.

Additionally, the Guarantees by the Guarantors are limited to the maximum amount that such Guarantors are permitted to guarantee under applicable law. In addition, the Guarantees and indemnities, security and any subordination of the Guarantors may be limited in certain circumstances and by certain matters, including where the cost of providing such credit support is disproportionate to the benefit accruing to the beneficiaries (including, without limitation, tax consequences, notarization and perfection expenses), legal limitations, requirement and restrictions (including financial assistance, corporate benefit, capital maintenance rules, fraudulent preference, earnings stripping, controlled foreign corporation and thin capitalization rules, tax restrictions and similar principles), where providing such credit support would expose officers to risk of personal or criminal liability or where doing so would unduly disrupt our business. As a result, any such Guarantor's liability under its Guarantee could be reduced to zero, depending on the amount of other obligations of and particular circumstances pertaining to such Guarantor. Further, under the circumstances discussed more fully below, in particular with respect to KUSA Inc., a court under U.S. federal or state fraudulent conveyance and transfer statutes could avoid the obligations under a guarantee or further subordinate it to all other obligations of the Guarantor. See "—If the Issuer defaults on the Notes, or a Guarantor defaults on a Guarantee, your right to receive payments on the Notes or a Guarantee may be adversely affected by English, Australian, Brazilian or United States insolvency laws." In addition, the Subsidiary Guarantors will be automatically released from their Guarantees upon the occurrence of certain events, including the following:

- the designation of a Subsidiary Guarantor as an unrestricted subsidiary;
- a Subsidiary Guarantor ceasing to be a subsidiary as a result of any foreclosure of any pledge or security interest in favor of first-priority lien obligations or other exercises of remedies thereunder; or
- the sale or other disposition of our equity interests in a Subsidiary Guarantor or a holding company of a Subsidiary Guarantor.

If the Guarantee of any Subsidiary Guarantor is released, no holder of the Notes will have a claim as a creditor against that subsidiary, and the indebtedness and other liabilities, including trade payables and preferred equity interests, if any, whether secured or unsecured, of that subsidiary will be structurally senior to the claim of any holders of the Notes. See "Description of the Notes—Guarantees."

The ability of the Common Security Agents, for the benefit of the holders of the Notes to enforce the Collateral comprising our Brazilian concessions and shares of our Brazilian entities may be impaired by ANP regulatory qualification requirements for potential buyers. Any assignment of ownership of the emerging concession rights under the Concession Agreements, including if such assignment occurs as a consequence of the enforcement of the Concessions Collateral, will be subject to the prior authorization from ANP (or the federal government of Brazil), following the procedures set forth in ANP Resolution No. 785/2019. For the authorization process, ANP will assess the technical, economic and legal qualifications of the proposed assignee. Also, if the enforcement of the Collateral comprising shares of Brazilian entities results in a change of control of the relevant company(ies) that requires the replacement of the performance guarantee delivered to ANP by the relevant company(ies) with respect to their concessions and the performance guarantee is presented in relation to the current controller of the concessionaire, such change of control will result in an assignment of the concession rights, which will then be subject to the provisions of the concession assignment procedure established under ANP Resolution 785, described above. The ANP authorization procedure may take months to be concluded, which may cause the Collateral foreclosure process in connection with the Collateral comprising our Brazilian concessions (and the shares of our Brazilian entities, if applicable) to be lengthy and delay the recovery of funds by the holders of the Notes. In addition to such procedure, the concessionaire shall notify the ANP within 30 days after the registration of the corporate resolution that formalize the change of control of the company, in accordance with the terms of the ANP Resolution 785.

We may not be able to repurchase the Notes upon a change of control.

Upon the occurrence of certain specific kinds of change of control events, we will be required to offer to repurchase all of the outstanding Notes at 101% of the principal amount thereof plus, without duplication, accrued and unpaid interest to the date of repurchase. Additionally, under the RBL facility, a change of control constitutes a review event that may permit the lenders to accelerate the maturity of borrowings and terminate their commitments to lend. See "Description of other financing arrangements—Reserve based lending facility—Mandatory prepayment and review events." The source of funds for any repurchase of the Notes and repayment of borrowings under the RBL facility would be our available cash or cash generated from our subsidiaries' operations or other sources, including borrowings, sales of assets or sales of equity. It is possible that we will not have sufficient funds at the time of a change of control to make the required repurchase of Notes or that restrictions in our other debt documents will not allow such repurchases. We may require additional financing from third parties to fund any such repurchases, and we may be unable to obtain financing on satisfactory terms or at all. Further, our ability to repurchase the Notes may be limited by law. In addition, certain important corporate events, such as leveraged recapitalizations that would increase the level of our indebtedness, would not constitute a change of control under the indenture. See "Description of the Notes—Change of Control."

Courts interpreting change of control provisions under New York law (which will be the governing law of the indenture) have not provided clear and consistent meanings of such change of control provisions, which leads to subjective judicial interpretation. In addition, a court case in Delaware has questioned whether a change of control provision contained in an indenture could be unenforceable on public policy grounds. It is possible that a change of control will be deemed to occur under other indebtedness in circumstances where a change of control has not occurred under the indenture.

We may enter into transactions that would not constitute a change of control that could affect our ability to satisfy our obligations under the Notes.

Legal uncertainty regarding what constitutes a change of control and the provisions of the indenture may allow us to enter into transactions, such as acquisitions, refinancing or recapitalizations, that would not constitute a change of control but may increase our outstanding indebtedness or otherwise affect our ability to satisfy our obligations under the Notes. The definition of change of control for purposes of the Notes includes a phrase relating to the transfer of "all or substantially all" of our assets taken as a whole. Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, your ability to require us to repurchase Notes as a result of a transfer of less than all of our assets to another person may be uncertain.

If the Issuer defaults on the Notes, or a Guarantor defaults on a Guarantee, your right to receive payments on the Notes or a Guarantee may be adversely affected by the laws of jurisdictions where our assets are located.

Bankruptcy, insolvency, administrative and other laws of jurisdictions where our assets are located may be materially different from, and subject to restrictions and limitations as compared to, the laws of jurisdictions with which you are familiar or which may be more favorable to your interests. Such differences may adversely affect your ability to enforce your rights under the Notes and the Guarantees. The Parent Guarantor and a number of the Guarantors are incorporated under the laws of Australia and, therefore, insolvency proceedings with respect to them would be likely to proceed under, and be governed by, Australian insolvency law. Karoon Petroleo & Gas Ltda is incorporated under the laws of Brazil and insolvency proceedings with respect to them may proceed under Brazilian law. The insolvency laws of Australia and Brazil are different from the insolvency laws of the United States. If we become insolvent, the treatment and ranking of holders of the Notes and of its other creditors and shareholders under Australian or Brazilian law may be different and less favorable than the resulting treatment and ranking if we were subject to the bankruptcy laws of the United States or other jurisdictions. Technicalities may undermine the ability of the holders of the Notes to directly participate or otherwise receive distributions in such insolvency proceedings. In addition, while none of the Guarantors is incorporated in England, certain of our security documents (including our intercreditor agreements) are governed by English law and certain of our assets are located in England or are contracts governed by English law. In the event of a bankruptcy, insolvency or similar event, proceedings could be initiated in any of these jurisdictions and/or the United States. Such multijurisdictional proceedings are likely to be complex and costly for creditors and otherwise may result in greater uncertainty and delay regarding the enforcement of your rights. There can also be no assurance that you will be able to effectively enforce your rights in such complex, multiple bankruptcy, insolvency or similar proceedings. See also "—If we become the subject of a bankruptcy proceeding, bankruptcy laws may limit your ability to realize value from the Collateral."

Under the provisions of Australian insolvency law, claims of secured creditors will, subject to certain exceptions as described below, rank ahead of claims of unsecured creditors in an insolvency process, and it will generally not be possible for the relevant Guarantors, the Issuer or other unsecured creditors to prevent or delay the secured creditors from enforcing their security to repay the debts due to them.

There are particular priority rules concerning "circulating assets", which typically encompass cash at bank (in un-blocked accounts), inventory and receivables. The claims of a secured creditor against circulating assets are by Australian insolvency law postponed to certain priority claims, including claims of employee creditors against the company, such as for wages, leave entitlements and redundancy payments. This can dilute the assets available to satisfy secured claims.

In addition, in Australia, certain claims of shareholders against the relevant company in a winding up are "subordinate claims," meaning that these claims will rank behind all other debts of, and claims against, the company by unsecured creditors. For example, in a winding-up, if shareholders were to claim damages against the debtor company, which claim is available to them in their capacity as a member of the company or arises from their buying, holding, selling or otherwise dealing in the shares of the debtor company (e.g., a claim for misleading and deceptive conduct), the payment of any amounts to shareholders claiming in this way would be deferred until all other non-shareholder creditor claims have first been satisfied. This statutory subordination, however, does not apply to claims of shareholders in a non-member capacity, for example, as a lender under a loan to an insolvent debtor company (there is no doctrine of equitable subordination recognized in Australia). In 2017, the Australian government passed reforms to Australian insolvency laws, including the introduction of an "ipso facto" moratorium. The legislation provides that enforcement of certain rights against a company under a contract, agreement or arrangement (such as a right entitling a creditor to terminate the contract or to accelerate payments or providing for automatic acceleration) are stayed for a certain period of time (and in some cases indefinitely), if the right arises for the reason that the corporation is in voluntary administration, or a managing controller is appointed to it, or it is, or announces that it will be applying to be, subject to a creditors' scheme of arrangement, or that relates to the company's financial position during any of those proceedings. The specified proceedings do not include liquidation. The ipso facto regime came into effect in Australia in 2018, and applies to ipso facto rights arising under contracts, agreements or arrangements entered into after July 1, 2018, subject to certain exclusions. In 2018, the Australian federal government also introduced regulations setting out the types of contracts and contractual rights which will be excluded from the stay. These regulations provide, among other things, that any ipso facto rights under a contract, agreement or arrangement that is or governs securities, financial products, bonds or promissory notes will be exempt from the moratorium. Furthermore, a contract, agreement or arrangement under which a party is or may be liable to subscribe for, or to procure subscribers for, securities, financial products, bonds or promissory notes is also excluded from the stay. Accordingly, these regulations should exclude the Notes and certain other related arrangements from the stay. However, since their commencement in 2018, the legislation and the regulations have rarely been the subject of judicial interpretation. If the regulations are determined not to exclude the Notes or related arrangements from their operation under the exclusions mentioned above or any other exclusion under the regulations, this may render the "ipso facto" provisions of the Notes or related arrangements unenforceable in Australia.

Brazilian law allows the granting of guarantees of notes, such as the Guarantees, but in the event that any Brazilian Guarantor files for judicial reorganization proceedings or bankruptcy, any debts owed to creditors (existing at the time of the filing) will be subject to such insolvency proceeding.

Brazilian bankruptcy law provides for three types of insolvency proceedings: judicial reorganization (recuperação judicial), which is an in-court voluntary reorganization, extrajudicial reorganization (*recuperação extrajudicial*), which is voluntary reorganization that is a form of "pre-pack" arrangement that is submitted to court confirmation to bind a dissenting or absent minority, and bankruptcy liquidation (- *falência*), which may be either voluntary or involuntary. In these cases, a creditor may be impaired to enforce its collateral in case it is subject to the proceeding, which is the case of pledges and mortgages in judicial reorganizations and may be the case in extrajudicial reorganizations as well (depending on the conditions proposed by the debtor to restructure its indebtedness). These types of collateral are not bankruptcy-remote and the relevant creditor may be subject to the proceeding and, therefore, paid either in the terms of the reorganization plan (in a judicial or extrajudicial reorganization scenario), or in the order established by the Brazilian bankruptcy law (in a bankruptcy liquidation scenario). Pursuant to Brazilian bankruptcy law, fiduciary liens over movable or immovable assets or fiduciary assignment of receivables or rights are bankruptcy-remote up to the value of Collateral and any balance not covered by the Collateral may be considered as unsecured credit, and, therefore, subject to the proceeding. However, in some circumstances, Brazilian courts have impaired creditors' ability to seizure and sell the collateral granted as fiduciary lien (either in a legal proceeding predicated on a default under the Notes and the Guarantees or during the stay period in a judicial reorganization proceeding), if such collateral is deemed essential to the continuation of the borrower's operations and business activities. A legal proceeding of this nature may last for several years. If the court accepts such defense in a legal proceeding against us outside of the context of a judicial reorganization (which is less common), we will have to post a bond to secure such legal proceeding consisting on other assets. We may not have other assets in sufficient value to offer in lieu of the Collateral. In a judicial reorganization proceeding, payment obligations under the Notes would not be included in the restructuring plan to the extent that they are fully secured by the Brazilian Share Collateral, as a fiduciary lien, and if the Judicial Reorganization Court considers the Brazilian Share Collateral essential to the maintenance of the debtor's activities, the holders of the Notes may not be able to enforce their rights in the Collateral governed by Brazilian law during the stay period, which lasts, according to the Brazilian bankruptcy laws, for 180 days, from the granting of the process of the judicial reorganization, and may be extended once for an equal period, on an exceptional basis, provided that the debtor has not caused the overcoming such term. Also, we cannot assure you that you would be successful in excluding the Collateral property subject to Brazilian Share Collateral agreements from the assets affected by insolvency proceedings.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Our borrowings under our RBL facility bear interest at a rate based on SOFR plus a margin, adjusted each interest period. We may incur additional indebtedness in future at floating interest rates. Interest rates could rise significantly in the future, thereby increasing our interest expenses associated with these obligations, reducing cash flow available for capital investments and limiting our ability to make payments on the Notes. We do not currently hedge our exposure to floating interest rates. If we decide to in the future, hedging may not be available or continue to be available on commercially reasonable terms. In addition, hedging itself carries certain risks, including that we may need to pay a significant amount (including costs) to terminate any hedging arrangements.

As of December 31, 2023, we had no interest rate hedging in place. In the future we may enter into interest rate swaps to reduce interest rate volatility. However any such swaps may not fully mitigate our interest rate risk, may prove disadvantageous, or may create additional risks. As of December 31, 2023, assuming our RBL facility was fully drawn, each 1% change in interest rates would result in a US$3,447,222 change in annual interest expense on such indebtedness.

Our fixed rate debt, including the Notes, does not expose us to the risk of increased interest payments as a result of changes in interest rates; however if interest rates rise significantly, we may find it difficult to raise new debt to refinance our debt ahead of its maturity.

There are restrictions on your ability to transfer or resell the Notes without registration or the filing of a prospectus under applicable securities laws.

We have not registered the Notes or the related Guarantees under the Securities Act or any state securities laws, and we do not currently intend to register the Notes. The holders of the Notes will not be entitled to require us to register the Notes for resale or otherwise. Neither the Notes nor the related Guarantees may be offered or sold in the United States, unless they are registered or the offer or sale is made pursuant to an exemption from registration under the Securities Act and applicable state securities laws. As a result, the transferability of the Notes may be negatively affected and you may be required to bear the risk of your investment for an indefinite period of time. By receiving the Notes, you will be deemed to have made certain acknowledgments, representations and agreements as set forth under "Notice to Investors."

Your ability to transfer the Notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop, or if developed be maintained, for the Notes.

The Notes are a new issue of securities for which there is no established public trading market, and we cannot assure you that in the future a market for the Notes will develop or that you will be able to sell the Notes that you have purchased. Although an application will be made for the listing and quotation of the Notes on the SGX-ST, we cannot assure investors that this application will be accepted. Affiliates of the initial purchasers have advised us that they intend to make a market in the Notes, if issued, as permitted by applicable laws and regulations, but they are not obligated to make a market in any of the Notes, and they may discontinue their market making activities at any time without notice. As a result, you cannot be sure that an active trading market will develop for the Notes. The liquidity of any market for the Notes will depend upon the number of holders of the Notes, our performance, the market for similar securities, the interest of securities dealers in making a market in the Notes and other factors. A liquid trading market may not develop for the Notes. If an active market does not develop or is not maintained, the price and liquidity of the Notes may be materially and adversely affected. Historically, the market for non-investment grade debt, such as the Notes, has been subject to disruptions that have caused substantial price volatility. We cannot assure you that if a market for the Notes were to develop, such a market would not be subject to similar disruptions. In addition, the Notes may trade at a discount from their value on the date you acquired the Notes, depending upon prevailing interest rates, the market for similar notes, our performance and other factors.

We may be unable to repay or repurchase the Notes at their maturity.

At the Notes' maturity, the entire outstanding principal amount of the Notes, together with accrued and unpaid interest, if any, will become due and payable. We may not have the funds to fulfill these obligations or the ability to renegotiate these obligations. If, upon the maturity date, other arrangements prohibit us from repaying the Notes, we could try to obtain waivers of such prohibitions from the lenders and holders under those arrangements, or we could attempt to refinance the borrowings that contain the restrictions. In these circumstances, if we were not able to obtain such waivers or refinance these borrowings, we would be unable to repay the Notes.

It may be difficult to realize the value of the Collateral, which may result in holder of the Notes not receiving full payment of the obligations owed under the Notes following an event of default.

The Collateral will be subject to any and all exceptions, materiality thresholds, defects, encumbrances, liens and other imperfections as may be specified in or permitted under the terms of the documents governing the security or otherwise accepted by the Trustee for the Notes and the Common Security Agents and any other creditors that have the benefit of first-priority liens on the Collateral, such as obligations under the RBL facility, from time to time, whether on or after the date the Notes are issued. The existence of any such exceptions, defects, encumbrances, liens and other imperfections could materially and adversely affect the value of the Collateral as well as the ability of the Common Security Agents to realize or foreclose on the Collateral.

The value of the Collateral at any time will depend on market and other economic conditions, including the availability of suitable buyers. No appraisals of any of the Collateral have been or will be prepared by us or on behalf of us in connection with this offering. By their nature, some or all of the pledged assets may be illiquid and may have no readily ascertainable market value. We cannot assure you that the fair market value of the Collateral as of the date of this offering memorandum equals or exceeds the principal amount of the debt secured thereby. The value of the assets pledged as Collateral could be impaired in the future as a result of changing economic conditions, our failure to implement our business strategy, competition, unforeseen liabilities and other future events. Accordingly, there may not be sufficient Collateral to pay all or any of the amounts due on the Notes and the RBL facility (and any additional future first-priority or pari passu second-priority obligations). Any claim for the difference between the amount, if any, realized by holders of the Notes from the sale of the Collateral and the RBL facility (and any additional future first-priority or pari passu second-priority obligations) will rank equally in right of payment with all of our other unsecured unsubordinated indebtedness and other obligations, including trade payables. Additionally, in the event that a bankruptcy case is commenced by or against us, if the value of the Collateral is less than the amount of principal and accrued and unpaid interest on the Notes and all other senior secured obligations, interest may cease to accrue on the Notes from and after the date the bankruptcy petition is filed and you will not be entitled to adequate protection of any such under-secured amount.

Pursuant to the Senior Lien Intercreditor Documents, any holders of indebtedness secured by first-priority liens in the Collateral, such as the lenders under the RBL facility, would direct any actions that may be taken in respect of the Collateral (including to commence and control enforcement proceedings against the Collateral and in connection with a restructuring) and, subject to certain exceptions, amendments or waivers of, or consents under, the security documents (provided that any such amendments, waivers or consents which relate to the nature or scope of the Collateral, the manner in which the proceeds of enforcement of the liens over the Collateral are applied or the release of the liens over the Collateral, shall, except as otherwise permitted or required by the Senior Lien Intercreditor Documents, the security documents or any applicable agreed security principles, require the approval of the Trustee for the Notes and the representative of each other secured creditor class under the Senior Lien Intercreditor Documents). The holders of indebtedness secured by first-priority liens are under no obligation to take into account the interests of the holders of the Notes and the Guarantees when determining whether and how to exercise their rights with respect to the Collateral, subject to the Senior Lien Intercreditor Documents, and their interest and rights may be significantly different from or adverse to yours. See "—Your right to exercise remedies with respect to the Collateral will be governed by, and materially limited by, the Senior Lien Intercreditor Documents."

The security interest of the Common Security Agents will be subject to practical challenges generally associated with the realization of security interests in Collateral. For example, the Common Security Agents may need to obtain the consent of a third party to obtain or enforce a security interest in a contract (including, without limitation, because taking or enforcing security could breach the terms of our contracts or trigger changes of control, termination rights or other rights or remedies of our counterparties under our contracts). We cannot assure you that the Common Security Agents will be able to obtain any such consent. We also cannot assure you that the consents of any third parties will be given when required to facilitate a foreclosure on such assets. Accordingly, the Common Security Agents may not have the ability to foreclose upon those assets and the value of the Collateral may significantly decrease.

In addition, the Collateral will be subject to liens permitted under the terms of the indenture, whether arising on or after the date the Notes are issued. The existence of any permitted liens could materially and adversely affect the value of the Collateral, as well as the ability of the Common Security Agents to realize or foreclose on the Collateral. Furthermore, not all of the Issuer's, the Parent Guarantor's and the Subsidiary Guarantors' assets secure the Notes, and those assets that do secure the Notes may be subject to customary exceptions and materiality thresholds. See "Description of the Notes—Security."

In particular, security over the assets of Guarantors other than Borrowing Base Obligors will be limited to the equity interests in Subsidiary Guarantors and wholly-owned material Subsidiaries, material intra-group receivables and material operating bank accounts, and where customary, a floating general security (or equivalent) over other assets of the Subsidiary Guarantors.

The Collateral will not include, among other things:

- in respect of U.S. obligors or assets located in the U.S., certain real property and leasehold interests in real property;
- in respect of U.S. obligors or assets located in the U.S., motor vehicles and other assets subject to certificate of title statutes and certain commercial tort claims;

- those assets over which the pledging or granting of security interests in such assets would be prohibited by applicable law, rule, regulation or contractual obligations (including leases, licenses or other agreements, government licenses or state or local license, franchises, charters or authorizations);

- certain bank accounts, including payroll and other employee wage and benefit accounts, tax accounts, contractual escrow accounts and fiduciary or trust accounts;

- goods (including inventory), moveable plant, equipment, vehicles or receivables if it would require labelling, segregation, periodic listing, notification, mapping or specification;

- in respect of U.S. obligors or assets located in the U.S., "intent-to-use" trademark applications until an amendment to allege use or statement of use has been filed;

- in respect of U.S. obligors or assets located in the U.S., margin stock; or

- certain other limited assets.

Our obligations to create and/or perfect security over our assets is also subject to other principles and restrictions. See "—Description of the Notes—Security—Limitation on Securities Collateral."

Some of these assets may be material to us and such exclusion could have a material adverse effect on the value of the Collateral.

Delivery of security interests in Collateral, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as Guarantor of the Notes, or any Guarantees after the Issue Date increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy.

Certain Collateral will be secured after the Issue Date of the Notes. For example, our subsidiary KUSA Inc., through which we hold our interest in the Who Dat, Dome Patrol and Abilene oil and gas assets, will not become a Borrowing Base Obligor until after the Issue Date, as it will only be a Corporate Guarantor on the Issue Date, and will grant security with respect to such assets at the same time as it grants security under the RBL facility. This will also apply with respect to future security interests granted in connection with the accession of further subsidiaries (if any) as additional Guarantors and the granting of security interests over their relevant assets and equity interests for the benefit of holders of the Notes and other secured parties under the Senior Lien Intercreditor Documents. Similarly, any Subsidiaries that are not Subsidiary Guarantors but are required under the RBL facility to become Subsidiary Guarantors in the future will be required to accede as guarantors not later than 90 days after the date we are required to deliver a compliance certificate under the RBL facility with respect to our financial statements (however the lenders of the agent under the RBL facility may choose to extend this date). The indenture will provide that the Parent Guarantor will cause its future wholly-owned subsidiaries that incur or guarantee certain debt (including the RBL facility) to accede to the Notes as Subsidiary Guarantors and execute and deliver a joinder to the security documents, and, to the extent required under the respective terms, a joinder agreement to any applicable security document and intercreditor agreements, in each case within 60 days of the date on which such future wholly-owned subsidiaries guaranteed such debt. However, the holders of the Notes will not have any control over when entities accede as guarantors and provide security for the benefit of the noteholders.

The granting of security interests to secure the Notes and the Guarantees may create hardening periods for such security interests in certain jurisdictions, including Australia, Brazil, the United States and England and Wales. The granting of shared security interests to secure future indebtedness permitted to be secured on the Collateral may restart or reopen such hardening periods in particular, as the Senior Lien Intercreditor Documents and the indenture will permit the release and retaking of security granted in favor of the relevant Notes in certain circumstances including in connection with the incurrence of future indebtedness. The applicable hardening period for these new security interests can run from the moment each new security interest has been granted, perfected or recreated. If the security interest granted, perfected or re-created were to be enforced before the end of the respective hardening period applicable in such jurisdiction, it may be declared void or ineffective and/or it may not be possible to enforce it. If the grantor of such security interest were to become subject to a bankruptcy or winding up proceeding after the Issue Date, any security interest in Collateral delivered after the Issue Date would face a greater risk than security interests in place on the Issue Date of being avoided by the grantor or by its trustee, receiver, liquidator, administrator or similar authority, or otherwise set aside by a court, as a preference under insolvency law. In Brazil, the declaration of bankruptcy should set the clawback period, which, in theory, must not be retroactive to more than 90 days prior to (i) the filing for bankruptcy; (ii) the filing for judicial reorganization; or (iii) the first protest of a title/bond issued by the company. The clawback period is a period during which certain transactions carried out by the bankrupt company may be revoked, such as: (i) the payment of debts not yet due by the debtor; (ii) the payment of debts that are due and payable by any means other than those specified in the contract; and (iii) the granting of a real property rights to secure a debt incurred prior to the clawback period. To the extent that the grant of any security interest is voided, holders of the Notes will lose the benefit of the security interest and may be required to disgorge prior payments or recoveries.

In particular and without limiting the foregoing, if the grantor of such security interest or a Guarantor were to become subject to a bankruptcy case under the U.S. Bankruptcy Code after the Issue Date of the Notes, any security interest in other Collateral, or any Guarantees delivered after the Issue Date of the Notes, would face a greater risk than security interests or Guarantees in place on the Issue Date (or with 30 days thereof) of being avoided by the pledgor or Guarantor (as debtor in possession) or by its trustee in bankruptcy or potentially by other creditors as a preference under the U.S. Bankruptcy Code if certain events or circumstances exist or occur. Specifically, security interests or Guarantees issued after the Issue Date (or within 30 days thereof) of the Notes may be treated under the U.S. Bankruptcy Code as if they were delivered to secure or guarantee previously existing or "antecedent" indebtedness. Any future pledge of Collateral or future issuance of a Guarantee in favor of the holders of the Notes, including pursuant to security documents or Guarantees delivered in connection therewith after the date the Notes are issued, may be avoidable as a preference if, among other circumstances, (i) the applicable pledgor or Guarantor is insolvent at the time of the pledge or the issuance of the Guarantee, (ii) the pledge or the issuance of the Guarantee permits the holders of the Notes to receive a greater recovery in a hypothetical chapter 7 case than if the pledge or Guarantee had not been given, and (iii) a bankruptcy case in respect of the applicable pledgor or Guarantor is commenced within 90 days following the pledge or the perfection thereof or the issuance of the Guarantee (as applicable), or, in certain circumstances, a year. Accordingly, if we or any Guarantor were to file for bankruptcy protection after the Issue Date of the Notes and (1) any liens not granted on the Issue Date of the Notes had been perfected, or (2) any Guarantees not issued on the Issue Date of the Notes (as applicable) had been issued, less than 90 days before commencement of such bankruptcy case (or, if applicable, one year), such liens or Guarantees are more likely to be avoided as a preference by the bankruptcy court than if delivered and promptly recorded on the Issue Date of the Notes (even if the liens perfected or other Guarantees issued on the Issue Date (or within 30 days thereof) of the Notes would no longer be subject to such risk). To the extent that the grant of any such security interest and/or Guarantee is avoided as a preference or otherwise, you would lose the benefit of the security interest and/or Guarantee (as applicable) and may be required to return prior payments.

Rights in the Collateral may be materially and adversely affected by the failure to perfect security interests in Collateral now or in the future.

Applicable law provides that a security interest in certain tangible and intangible assets can only be properly perfected and its priority retained through certain actions undertaken by the secured party, the Issuer or relevant Guarantor and/or third parties such as contractual counterparties, banks or other institutions with whom deposit accounts or other assets are held or other third parties. The liens in the Collateral securing the Notes may not be perfected with respect to the claims of the Notes if the Common Security Agents, the Issuer or any such Guarantor, or any third party, as applicable, are not able to, or do not, take the actions necessary to perfect any of these liens. We and the Guarantors have limited obligations to perfect the Noteholders' security interest in specified Collateral (including, without limitation, if it would restrict our ability to conduct our operations and business in the ordinary course or as otherwise permitted). Applicable third parties generally will not be obliged to take action to assist in perfection of security. In addition, applicable law provides that certain property and rights acquired after the grant of a general security interest, such as real property, certain intellectual property and certain proceeds, can only be perfected at the time such property and rights are acquired and identified.

Under Brazilian law, the perfection of security interests over assets depends on certain registration requirements to be considered existent, valid and/or binding, as applicable. Depending on the assets over which the security interest is to be created, (a) the signature of the parties who sign the relevant security agreements outside Brazil must be notarized by a public notary licensed pursuant to the laws of the place of signature and the signature of such public notary must be authenticated by the Brazilian Consulate with jurisdiction over the place of execution, except when such public notary is from a country that is signatory of the Hague Convention Abolishing the Requirement of Legalization for Foreign Public Documents dated as of October 5, 1961, in which case it must be duly apostilled by the applicable foreign authority (and the authentication by a Brazilian Consulate is not required); (b) the relevant security agreement must be translated into Portuguese by a sworn translator (tradutor juramentado) in Brazil; and (c) the relevant security agreement and the sworn translation thereof must be registered with the appropriate Registry of Deeds and Documents (Cartório de Registro de Títulos e Documentos) and/or Real Estate Registry (Cartório de Registro Geral de Imóveis), as applicable, in Brazil. In case the relevant security agreement is signed electronically, no such notarization or apostille mentioned in item (a) above will apply, but its sworn translation and registration of the document with the appropriate Registry of Deeds and Documents (Cartório de Registro de Títulos e Documentos) and/or Real Estate Registry (Cartório de Registro Geral de Imóveis), as applicable, will still be required. In relation to the registrations with the applicable Registry of Titles and Deeds, Brazilian law was recently changed. Previously, the effects of the registration would be retroactive to the date of the agreement if such agreement was filed for registration within 20 days of its date; however, the law now states that the effects of the registration will no longer be retroactive and shall only be effective from the date of registration onwards. In the event of a failure to create and perfect liens on the Collateral, including by making such registrations, the Notes will not be secured by such assets.

Note that, in case of electronic signatures in Brazil, the electronic certification needs to be recognized by the Brazilian system of digital certification (known as "ICP-Brasil"). Certain notary offices are more flexible and accept foreign certification companies, provided that they meet certain requirements. However, considering that most notary offices have shown little to no flexibility, a more conservative approach is generally adopted to require signatories to obtain a certification validated by ICP-Brasil.

In addition to the above, in Brazil, the perfection of security interests over certain assets may require additional formalities. In relation to the Brazilian Security Documents, the following additional formalities are required: (i) the registration of the relevant liens in the company's articles of association, in relation to the fiduciary assignment over the quotas issued by the company's Brazilian subsidiary; (ii) giving of notice to ANP informing it of the inclusion of the noteholders as secured parties under the pledge of concessions, within 30 days after the execution of the relevant amendment to the pledge of concessions; and (iii) delivery of notices and obtaining consents, as applicable, from the counterparties to the conditional Assignment and Fiduciary Assignment of Credit Rights Agreement. Under the current wording of the Conditional Assignment and Fiduciary Assignment of Credit Rights Agreement, the Company must use reasonable efforts to obtain such consents, but the Collateral over such assigned agreements and assigned credit rights that require such consents will not be perfected until such consents are duly obtained. Therefore, the Notes will not be secured by any assets, perfection over which requires consents to be obtained, until such consents are obtained.

With respect to Australia, the granting of security interests over personal property is generally governed by the Personal Property Securities Act 2009 (the "PPSA"). The creation, perfection and/or priority of security over assets which are not subject to the PPSA (including, without limitation, interests in real property), is typically subject to other requirements and formalities under applicable laws of the relevant State and or Territory of Australia or, as applicable, federal law. We have limited obligations to create, perfect or preserve the priority of security interests in such assets. See "Description of the Notes—Security—Limitation on Securities Collateral."

Under the provisions of the PPSA, security interests that are unperfected at the time of the appointment of a voluntary administrator or the occurrence of certain other insolvency events in relation to the relevant grantor of such security interest will, in accordance with the rules set out in Part 8.2 (*Vesting of certain unperfected security interests*) of the PPSA, automatically vest in the grantor upon the appointment of the voluntary administrator or the occurrence of the relevant insolvency event. The secured party will lose its security interest in the applicable collateral as a result and can only assert an unsecured claim against the relevant grantor.

In order to prevent the security interest from vesting in the grantor on the applicable insolvency event, a security interest must be perfected in accordance with the provisions of the PPSA. Perfection can only be achieved once the security interest is enforceable against the grantor (known as attachment) and against third parties (including by execution of a security agreement). The most common method of perfection is by registration of the security interest on the Personal Property Securities Register. Where the grantor is a company, there are time limits for registration. For example, security interests that were not perfected within 20 business days after the relevant security agreement came into force (subject to limited exceptions) will vest in the company upon the appointment of the voluntary administrator or the occurrence of other applicable insolvency events. Other methods of perfection include taking possession or control of the collateral (in each case in accordance with the PPSA). Those methods of perfection are only available in relation to specific types of property, the most common example being financial property, such as shares, units and bonds and certain bank accounts. Perfection by possession or control can be lost if, for example, a secured party ceases to have control of collateral (and did not also have a valid registration in respect of the security interest).

The Common Security Agents will not monitor and has no obligation to monitor, and there can be no assurance that we will inform the Common Security Agents of, the future acquisition of property and rights that constitute Collateral, and that the necessary action will be taken to properly perfect the security interest in such after-acquired Collateral. Such failure may result in the loss of the security interest in the Collateral or the priority of the security interest in favor of the Common Security Agents, as applicable, against third parties and the holders of the Notes would not be entitled to the proceeds from the sale of all or any of the Collateral that is the subject of such failure or any other remedies in connection therewith. Even if the Common Security Agents do take all actions necessary to create properly-perfected security interests, any such security interests that are perfected after the date of the indenture would remain at risk of being avoided as a preferential transfer or otherwise in any bankruptcy even after the security interests perfected on the closing date were no longer subject to such risk.

In addition, even if the Common Security Agents do properly perfect liens on Collateral acquired in the future, such liens may (as described further herein) potentially be avoidable as a preference in any bankruptcy case under certain circumstances. See "—Delivery of security interests in Collateral, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as Guarantor of the Notes, or any Guarantees after the Issue Date increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy."

The security interests in the Collateral will be granted to the Common Security Agents rather than directly to the holders of the Notes.

The security interests in the Collateral that will secure our obligations under the Notes and the obligations of the Guarantors under the Guarantees will not be granted directly to the holders of the Notes but will be granted only in favor of the Common Security Agents (or their respective agents) for the benefit of all secured indebtedness under the Senior Lien Intercreditor Documents (including, without limitation, the RBL facility and the Notes). For the avoidance of doubt, where any reference is made to first-priority liens or second-priority liens (or any similar or analogous expressions), it includes a reference to the common security held by the Common Security Agents for the collective benefit of all secured parties (or more than once class of secured parties) securing the relevant secured debt in such order of priority. The ability of the Common Security Agents to perfect and/or enforce certain of the Collateral may be restricted by applicable law.

The indenture will provide that only the Common Security Agents have the right to enforce the security documents for the Notes. The ability of the holders of the Notes to instruct the Common Security Agents to enforce the security documents will be limited under the Senior Lien Intercreditor Documents and the Second Lien Intercreditor Agreement. See "—Indebtedness under the Notes will be subject to the Senior Lien Intercreditor Documents which provide that the RBL facility and other certain future first-priority indebtedness will be senior to the Notes to the extent of the value of the Collateral securing those obligations."

As a consequence, holders of the Notes will not have direct security interests and will not be entitled to take enforcement action in respect of the Collateral, except through the Common Security Agents and may only instruct the Common Security Agents to take enforcement action to the extent provided in the Senior Lien Intercreditor Documents.

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

Under various circumstances, Collateral will be released automatically, including:

- a sale, transfer or other disposition of such Collateral (including to the Issuer, the Parent Guarantor or a Subsidiary Guarantor but without prejudice to any obligation of any Group member to provide replacement security) in a transaction not prohibited under the indenture;

- with respect to Collateral held by the Parent Guarantor or a Subsidiary Guarantor, upon the release of the Parent Guarantor or such Subsidiary Guarantor from its Guarantee, as applicable;

- with respect to Collateral held by the Issuer, upon the release or discharge of the Issuer's obligations under the Notes pursuant to the indenture;

- pursuant to the Senior Lien Intercreditor Documents with respect to enforcement actions by the holders of the first-priority obligations;

- pursuant to the Second Lien Intercreditor Agreement with respect to enforcement actions by the holders of the then-controlling second-priority obligations; and

- if the Notes have been discharged or defeased pursuant to a legal defeasance or covenant defeasance under the indenture.

The Guarantee of a Subsidiary Guarantor or a holding company of such Subsidiary Guarantor will be automatically released to the extent it is released in connection with a sale of such Subsidiary Guarantor in a transaction not prohibited by the indenture. The indenture also permits us to designate one or more of our restricted subsidiaries that is a Subsidiary Guarantor of the Notes as an unrestricted subsidiary. If we designate a Subsidiary Guarantor as an unrestricted subsidiary for purposes of the indenture, all of the liens on any Collateral owned by such subsidiary or any of its subsidiaries and any Guarantees of the Notes by such subsidiary will be released under the indenture but not necessarily under the RBL facility and the aggregate value of the Collateral will be reduced. In addition, the creditors of the unrestricted subsidiary and its subsidiaries will have a claim on the assets of such unrestricted subsidiary and its subsidiaries that is senior to the claim of the holders of the Notes. See "—If we classify subsidiaries as Unrestricted Subsidiaries, they will not be subject to any of the covenants in the indenture, and we may not be able to rely on the cash flow or assets of our Unrestricted Subsidiaries to pay the Notes or our other indebtedness."

We will, in most cases, have control over the Collateral, and the sale of particular assets by us could reduce the pool of assets securing the Notes and the Guarantees.

The collateral documents relating to the liens over the Collateral will allow us to remain in possession of, retain exclusive control over, freely operate, and collect, invest and dispose of any income from, the Collateral. We may, therefore, among other things, without any release or consent by the Collateral Security Agents or the Trustee, conduct ordinary course activities with respect to Collateral permitted by the indenture and the Security Documents, such as selling, factoring, abandoning or otherwise disposing of Collateral and making ordinary course cash payments (including repayments of indebtedness), all of which could reduce the pool of assets securing the Notes. See "Description of the Notes—Security."

If we become the subject of a bankruptcy proceeding, bankruptcy laws may limit your ability to realize value from the Collateral.

The right of the Common Security Agents to foreclose upon, repossess, and dispose of the Collateral upon the occurrence and during the continuance of an event of default under the indenture is likely to be significantly impaired by applicable bankruptcy law if a bankruptcy case were to be commenced by or against us before the Common Security Agents repossessed and disposed of the Collateral (and sometimes even after). Upon the commencement of a case under the Title 11 of the United States Code (the "U.S. Bankruptcy Code"), a secured creditor such as the Common Security Agents is prohibited from repossessing its security from a debtor in a bankruptcy case, or from disposing of security previously repossessed from such debtor, without prior bankruptcy court approval, which may not be given or could be materially delayed. Moreover, the U.S. Bankruptcy Code permits the debtor to continue to retain and use collateral even though the debtor is in default under the applicable debt instruments, provided that the secured creditor is given "adequate protection." The meaning of the term "adequate protection" may vary according to circumstances, but it is intended in general to protect the value of the secured creditor's interest in the collateral as of the commencement of the bankruptcy case and may include cash payments or the granting of additional or replacement security or superpriority administrative expense claims if and at such times as the bankruptcy court in its discretion determines that the value of the secured creditor's interest in the collateral is declining during the pendency of the bankruptcy case. A bankruptcy court may determine that a secured creditor may not require compensation for any such diminution in the value of its collateral if the value of the collateral exceeds the debt it secures.

In view of the lack of a precise definition of the term "adequate protection" and the broad discretionary power of a bankruptcy court, it is impossible to predict:

- whether or when payments under the Notes could be made following the commencement of a bankruptcy case, or the length of any delay in making such payments;
- whether or when the Common Security Agents could repossess or dispose of the Collateral;
- the value of the Collateral at the time of the bankruptcy petition or any other relevant time; or
- whether or to what extent holders of the Notes would be compensated for any delay in payment or loss of value of the Collateral through the requirement of "adequate protection."

Any disposition of the Collateral during a bankruptcy case would also require permission from the bankruptcy court (which may not be given or could be materially delayed). Furthermore, in the event a bankruptcy court determines the value of the Collateral is not sufficient to repay all amounts due on debt which is to be paid first out of the proceeds of the Collateral, the holders of the Notes would hold a secured claim only to the extent of the value of the Collateral to which the holders of the Notes are entitled and unsecured "deficiency" claims with respect to any shortfall or under-collateralization. The U.S. Bankruptcy Code only permits the payment and accrual of post-petition interest, costs and attorneys' fees to a secured creditor during a debtor's bankruptcy case to the extent the value of its collateral is determined by the bankruptcy court to exceed the aggregate outstanding principal amount of the obligations secured by the collateral.

In Australia notwithstanding the statutory moratorium that applies on claims against a company for which a voluntary administrator is appointed, a secured creditor that holds a validly perfected security interest over the whole, or substantially the whole, of the company's property, will be permitted to enforce its security by appointing a receiver and manager to the company within 13 business days of the voluntary administrator's appointment. If this occurs, the secured creditor's receiver and manager will have control over the assets and undertaking of the company and can deal with the company's assets as directed by the secured creditor. If a secured creditor elects not to appoint a receiver and manager, or if the secured creditor does not have security over the whole or substantially the whole of the property of the company, the secured creditor will need to wait for the voluntary administration process to come to an end.

The voluntary administration regime provides a tight timetable for the holding of meetings of creditors and for reporting by the voluntary administrator to creditors on the available options for the company (usually either a winding up or a "work out" pursuant to a deed of company arrangement ("DOCA")). A DOCA will ordinarily provide for the company to make a distribution to creditors from a "deed fund" in exchange for the extinguishment and release of their claims against the company. Importantly, secured creditors with validly perfected security interests will not be bound by the terms of a DOCA if they do not vote in favor of it. For this reason, a DOCA is usually only proposed in circumstances where the secured creditors' interests are accommodated.

In the event that receivers and managers are appointed to the company to realize secured property in order to pay down secured debt, it is relevant to note that property of the company that is subject to a circulating security interest must be used by the receivers to pay certain priority creditor claims (including employee entitlements) before any amounts can be remitted to the secured creditor. There are equivalent statutory priorities in respect of property the subject of a circulating security interest in a liquidation context. Accordingly, if the secured property is insufficient to pay down priority claims as well as the claims of secured creditors (in accordance with any contractual priorities as between secured creditors), the secured debt may not be discharged in full.

In the event that a liquidator is appointed to a company, that liquidator has an obligation to maximize the pool of assets available to creditors and in order to achieve that, the liquidator is given broad statutory powers to set aside transactions entered into by the company in the lead up to its insolvency. The main classes of transactions include uncommercial transactions, unfair preferences, creditor-defeating transactions and unfair loans. A liquidator can also commence proceedings in the name of the company against its directors (for example, for breach of duties) or against third parties. Despite the appointment of a liquidator, a secured creditor with a validly perfected security interest may realize or otherwise deal with its secured property, and a liquidator cannot deal with secured property unless the relevant secured creditor surrenders its security.

In Brazil, the right and ability of the Common Security Agents, for the benefit of the holders of the Notes, to realize or foreclose on the Collateral upon the occurrence of an event of default is likely to be significantly impaired by applicable bankruptcy law if a judicial reorganization is filed by the debtor or a bankruptcy proceeding were to be commenced by or against us prior or during the foreclosure of the Collateral by the Common Security Agents. Under applicable bankruptcy law, in the case of a judicial reorganization, the creditors secured by fiduciary lien are not subject to the restructuring plan up to the limit of the collateral, which means that the foreclosure of the collateral is permitted, except during the stay period if the collateral is granted over assets that are deemed essential to the company's restructuring. In case of bankruptcy, the collateral would not be part of the bankrupt estate since ownership of the collateral would have been transferred to the creditor, or if the asset collateralized no longer exists when the bankruptcy is decreed, the creditor who holds the collateral must be repaid in cash (through a restitution proceeding). On the other hand, the mortgage and pledge collaterals are subject to the judicial reorganization and bankruptcy. Therefore, a mortgage/pledge cannot be enforced against a debtor under judicial reorganization or bankruptcy, and the creditor does not have the right to take possession of the asset given as collateral. However, in a judicial reorganization scenario, the creditor holding the mortgage/pledge is entitled to participate in the proceedings and vote on a restructuring plan. The confirmation of the judicial reorganization plan binds creditors secured by mortgage/pledge; however, the collateral over the asset can only be released with the consent of the creditor holding the collateral.

Certain of our assets may be located in, or subject to the laws of, jurisdictions other than the jurisdiction in which the applicable Guarantor is organized. Subject to limited exceptions, security will be governed by the laws of the jurisdiction in which the relevant Guarantor is organized, and we will not have to create or perfect security under local law over assets in other jurisdictions (however security over equity interests issued by a Guarantor will be governed by the laws of the issuer's jurisdiction and English law security has been granted over certain of our assets located in England, including bank accounts). See "Description of the Notes—Security—Limitation on Securities Collateral." Security under the laws of the Guarantor's jurisdiction may not be effective to create and/or perfect the security interests in assets located in any other jurisdiction. In addition, such assets may be subject to local laws which impair the effectiveness or priority of such security, your or the Common Security Agents' ability to enforce or otherwise exercise rights with respect to the applicable assets or your ability to participate in or otherwise receive distributions with respect to such assets. Further, proceedings could be initiated in multiple jurisdictions, and multijurisdictional proceedings are likely to be complex and costly for creditors and otherwise may result in greater uncertainty and delay regarding the enforcement of your rights. The impact of such principles and matters on the value of, and/or your ability to realize, the value of any such Collateral may be material.

Also, the Senior Lien Intercreditor Documents and the Second Lien Intercreditor Agreement will provide that, in the event of a bankruptcy by the Issuer or a Guarantor, the holders of the Notes will (and in the case of the Second Lien Intercreditor Agreement, may) be subject to certain restrictions with respect to their ability to object to a number of important matters or to take other actions following the filing of a bankruptcy petition with respect to the Collateral prior to (with respect to the Senior Lien Intercreditor Documents) the discharge of the obligations under the RBL facility and other first-priority secured obligations. In particular, the Senior Lien Intercreditor Documents will, and the Second Lien Intercreditor Agreement may, impose certain limitations on the holders of the Notes with respect to their rights to seek adequate protection with respect to the liens on the Collateral, to object to proposed debtor-in-possession financing or the use of cash Collateral that has been consented to by the holders of indebtedness subject to first-priority liens, such as the lenders under the RBL facility, or the Common Security Agents for the then-controlling second-priority obligations, or to raise certain objections to any sale of the Collateral that has been consented to by the holders of indebtedness subject to first-priority liens or the Common Security Agents for the then-controlling second-priority obligations. See "Description of the Notes—Security Documents—Senior Lien Intercreditor Documents" and "Description of the Notes—Security Documents—Second Lien Pari Passu Intercreditor Agreement."

The Collateral and related Guarantees may be diluted under certain circumstances.

The indenture, the RBL facility and any agreements governing our other indebtedness will permit us to incur additional secured indebtedness, including additional notes, parity lien obligations and other priority lien obligations, subject to our compliance with the restrictive covenants applicable to us at the time we incur such additional secured indebtedness. Such additional indebtedness may be secured by first-priority liens or senior-priority over the Collateral, or (including in the case of any additional notes issued under the indenture) by second-priority liens over the Collateral on a pari passu basis with the liens securing the indebtedness under the Notes. An issuance of any such additional indebtedness would therefore dilute the value of the Noteholders' rights to the Collateral.

The security interests of the noteholders in after-acquired assets may not be perfected in a timely manner or at all.

If additional restricted subsidiaries are formed or acquired and become Subsidiary Guarantors under the indenture, or additional assets are acquired by a Subsidiary Guarantor, additional security documents would be required to be entered into, additional financing statements would be required to be filed and/or other filings or steps would need to be made and/or other steps may need to be taken to create and/or perfect the security interest in the assets of such Subsidiary Guarantors. See "—Rights in the Collateral may be materially and adversely affected by the failure to perfect security interests in Collateral now or in the future." Depending on the type of the assets constituting after-acquired

Collateral, additional action may be required to be taken to create and/or perfect the security interest in such assets, such as the entry into of additional security documents, the delivery of physical Collateral, if permitted by the Senior Lien Intercreditor Documents, or the execution and recordation of mortgages or deeds of trust or the execution of amendments to the existing Security Documents to duly describe and detail the assets comprising the after-acquired collateral. Our obligations to take such steps are limited. See "Description of the Notes—Security—Limitation on Securities Collateral." Even if such additional actions are taken to perfect the security interest in such after- acquired Collateral, to the extent a security interest in any Collateral is not perfected on the Issue Date of the Notes, such security interest might be avoidable in bankruptcy as a preferential transfer or otherwise, which could impact the value of the Collateral. See "—Delivery of security interests in Collateral, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as Guarantor of the Notes, or any Guarantees after the Issue Date increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy" below.

Certain Collateral securing the Notes will not be in place until after the Issue Date.

The Issuer and KUSA Inc. will grant to the Common Security Agents for the benefit of the RBL facility, the holders of the Notes and other secured indebtedness from time to time the security described in "Description of the Notes—Security—U.S. Security" which does not include security over their interests in the Who Dat assets, except to the extent required to be provided by a Subsidiary Guarantor that is not a Borrowing Base Obligor. See "—It may be difficult to realize the value of the Collateral securing the Notes, which may result in a holder of the Notes not receiving full payment of the obligations owed under the Notes following an event of default." We intend to designate those interests as borrowing base assets under the RBL facility. Once they are so designated, KUSA Inc. will become a Borrowing Base Obligor (if it has not already become a Borrowing Base Obligor by becoming a borrower under the RBL facility) and, subject to relevant exceptions and limitations, will grant additional security over assets relating to Who Dat. Holders of the Notes will be secured on a second lien basis (subject to the security principles and applicable local law) over those assets. Until that designation occurs, holders of the Notes will only have the benefit of security over the Who Dat assets to the extent described in "Description of the Notes—Security—Limitations on securities collateral."

Security over certain assets constituting the Collateral on which security interest in favor of the Common Security Agents is required may not be perfected on the Issue Date.

Security interests over the Brazilian assets of the Borrowing Base Obligors constituting the Collateral, which will be required under the Indenture, may not be perfected on the Issue Date. To the extent such security interests are not perfected on such date, we will be required to deliver fully executed agreements to the Common Security Agent with respect to pledging and/or assigning such interests and to provide all necessary notifications by the Issue Date and have such security interests thereafter perfected within eight business days and twenty days, subject to extensions, in relation to, respectively, the security documents to be registered with Registry of Titles and and Deeds and with Real Estate Registry from the date of the execution of the relevant security documents, but there can be no assurance that such security interests will be perfected on a timely basis. See "Description of the Notes—Security—Brazilian security." In the event that significant time passes between the issuance of the Notes and the perfection of the security interests with respect to such assets, the validity of such security interests may be questioned in Brazilian insolvency proceedings. In a judicial reorganization, creditors are classified in four classes, depending on the nature of their credits, for the purpose of voting and receiving the payment, but there is no preference between one class and another. Creditors with *in rem* guarantees (pledge and mortgage) are subject to judicial reorganization and must be classified as secured creditors. Creditors secured by fiduciary liens, in turn, are not subject to the proceeding, which means that the holder of such liens can enforce the collateral. If a reorganization court determines that the collateral of a creditor (both *in rem* and/or fiduciary) is not valid, such creditor will be classified as an unsecured creditor in the judicial reorganization.

The waterfall of payments in bankruptcy is established by Brazilian bankruptcy law, and creditors with *in rem* guarantees have priority over unsecured creditors. Creditors holding fiduciary liens are also not subject to bankruptcy and must receive the asset object of the collateral as payment or the equivalent in cash. If a bankruptcy court determines that the collateral of a creditor (both *in rem* and/or fiduciary) is not valid, such creditor will be classified as an unsecured creditor in the judicial reorganization.

Additionally, our subsidiary KUSA Inc., through which we hold our interest in the Who Dat, Dome Patrol and Abilene oil and gas assets, will not become a Borrowing Base Obligor until after the Issue Date, as it will only be a Corporate Guarantor on the Issue Date, and will grant security with respect to such assets at the same time as it grants security under the RBL facility. Perfection of the security interests after the Issue Date materially increases the risk that the liens with respect to those interests could be avoided, in the event of a bankruptcy. See "—Delivery of security interests in Collateral, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as Guarantor of the Notes, or any Guarantees after the Issue Date increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy" for further details regarding such consequences with respect to the U.S. Bankruptcy Code.

The Collateral is subject to casualty risks, which may limit your ability to recover as a secured creditor if there are losses to the Collateral and have an adverse impact on our operations and results.

We maintain insurance or otherwise insure against certain hazards. There are, however, losses that may not be insured. If there is a total or partial loss of any of the pledged Collateral, we cannot assure you that any insurance proceeds received by us will be sufficient to satisfy all the first-priority secured obligations, including the RBL facility, and the second-priority secured obligations, including the Notes and related Guarantees. In the event of a total or partial loss affecting any of our assets, certain items may not be easily replaced. Accordingly, even though there may be insurance coverage, the extended period needed to obtain replacement units or inventory may cause significant delays, which may have an adverse impact on our operations and results. In addition, certain laws and regulations may prevent rebuilding substantially the same facilities in the event of a loss, which may have an adverse impact on our operations and results. Such adverse impacts may not be covered, or fully covered, by property or business interruption insurance.

Indebtedness under the Notes will be subject to the Senior Lien Intercreditor Documents which provide that the RBL facility and certain other future first-priority indebtedness will be senior to the Notes to the extent of the value of the Collateral securing those obligations.

Substantially all the assets owned by the Issuer and the Guarantors on the issue date of the Notes or thereafter acquired, and all proceeds therefrom, will be subject to first-priority liens in favor of the lenders and other secured parties under the RBL facility and certain other future creditors, and obligations under the Notes are secured by a second-priority lien on such Collateral. The second-priority liens on the Collateral securing the Notes and Guarantees are therefore lower in priority than the liens securing the Issuer and/or any Guarantor's obligations under the RBL facility. In addition, under the indenture, the Issuer and the Guarantors may, from time to time, be permitted to incur additional indebtedness, which may be secured by liens on the Collateral that rank senior in priority to the liens securing the Notes and the Guarantees. As such, holders of the indebtedness under our RBL facility and any such other first-priority indebtedness will be entitled to realize proceeds from the realization of value of the Collateral to repay such indebtedness in full before the holders of the Notes and the Guarantees will be entitled to any recovery from such Collateral. As a result, the Notes and the Guarantees are effectively junior in right of payment to indebtedness under the RBL facility, and any such other first-priority indebtedness, to the extent that the realizable value of the Collateral does not exceed the aggregate amount of such indebtedness.

It is possible that the realizable value of the Collateral securing the Notes and the Guarantees may not be sufficient, in an insolvency or similar proceeding, to satisfy the claims of all effectively senior creditors, along with those of the holders of the Notes and the Guarantees and any other creditors of indebtedness ranking pari passu with the holders of the Notes and the Guarantees.

Your right to exercise remedies with respect to the Collateral will be governed by, and materially limited by, the Senior Lien Intercreditor Documents.

The rights of holders of the Notes with respect to the Collateral will be governed by, and materially limited by, the Senior Lien Intercreditor Documents. The Senior Lien Intercreditor Documents provide that, at any time that any obligations that are secured by first-priority liens remain outstanding, any actions that may be taken in respect of the Collateral (including the ability to commence enforcement proceedings against the Collateral and to control the conduct of such proceedings) will be at the direction of the holders of such indebtedness. Under such circumstances, as set out below, the Trustee (or its agent) on behalf of the holders of Notes will not have the ability to control or direct such actions, even if an event of default under the indenture governing the Notes has occurred or if the rights of the holders of Notes are materially and adversely affected. The holders of indebtedness secured by first-priority liens are under no obligation to take into account the interests of the holders of the Notes and the Guarantees when determining whether and how to exercise their rights with respect to the Collateral, subject to the Senior Lien Intercreditor Documents, and their interest and rights may be significantly different from or adverse to yours.

In the event that the Issuer or any Guarantor is declared bankrupt, becomes insolvent or is liquidated or reorganized, their obligations under the RBL facility and other first-priority secured obligations will be entitled to be paid in full from their assets pledged as security for such obligation before any payment from such assets or the proceeds thereof may be made with respect to the Notes. Holders of the Notes would then participate ratably in the remaining assets pledged as Collateral, with all holders of indebtedness that are deemed to rank equally with the Notes based upon the respective amount owed to each creditor. Also, under the Senior Lien Intercreditor Documents, the holders of the Notes may be required to turn over certain funds they may receive in any insolvency or liquidation proceeding to the lenders under the RBL facility and other first-priority secured obligations under certain circumstances.

In addition, if we and/or any Guarantors experience certain defaults under the RBL facility and other first-priority secured obligations, the lenders and other secured parties of such obligations could declare all of the funds borrowed thereunder, together with accrued and unpaid interest, immediately due and payable and foreclose on, or take other enforcement action with respect to, the assets pledged as Collateral. However, if there were an event of default under the Notes, the holders of obligations that are secured by first-priority liens could decide not to proceed against the Collateral securing the Notes, regardless of whether or not there is a default under such obligations that are secured by first-priority liens. In the event such holders do not exercise their right with respect to the Collateral, the only remedy available to the holders of the Notes would be to sue for payment on the Notes, subject to the rights of the Common Security Agents to realize or foreclose on the Collateral under the Senior Lien Intercreditor Documents following acceleration of the Notes.

While any indebtedness secured by first-priority liens remains outstanding, the holders of the Notes and the Guarantees and any other creditors of indebtedness secured on a pari passu basis with the holders of the Notes and the Guarantees will be entitled to exercise certain rights or remedies with respect to the Collateral only after a standstill period of 180 days and provided the holders of such first-priority secured indebtedness have not taken enforcement action with respect to a material portion of the Collateral and no insolvency event has occurred and no insolvency proceeding has been commenced by or against us or any Guarantor, provided that, with respect to the Borrowing Base Priority Collateral while any first-priority lien obligations (other than indebtedness under the RBL facility (including any refinancing of the RBL facility)) is outstanding, the holders of such first priority liens (rather than the holders of the Notes) will have the right to exercise such rights or remedies following such standstill period.

Under the Senior Lien Intercreditor Documents, the authorized representative of the holders of the Notes may not object following the filing of a bankruptcy petition to any debtor-in-possession financing or to the use of the Collateral to secure that financing, if the same has been consented to by the lenders under the RBL facility (or their authorized representative), subject to certain conditions and limited exceptions. See "Description of the Notes—Security Documents." After such a filing, the value of the Collateral could materially deteriorate, and the holders of the Notes would be unable to raise an objection.

Even though the holders of the Notes will benefit from a second-priority lien on the Collateral, if there is more than one series of second-priority indebtedness outstanding, the notes and Guarantees will be subject to the Second Lien Intercreditor Agreement and the representative of the holders of other second-priority indebtedness may control actions with respect to the Collateral.

In addition to the limitations on the rights of the holders of the Notes with respect to the Collateral under the Senior Lien Intercreditor Documents, the rights of the holders of the Notes with respect to the Collateral that will secure the Notes on a second-priority basis will also be subject to the Second Lien Intercreditor Agreement if there is more than one series of second-priority indebtedness. Under the terms of the Second Lien Intercreditor Agreement, the representative of holders of another series of second-priority indebtedness may control actions with respect to the Collateral if such other series of second-priority indebtedness has an aggregate principal amount greater than the aggregate principal amount outstanding of the Notes. The interests of holders of other second-priority indebtedness may differ from the interests of holders of the Notes and there can be no assurance that the representative of any other series of second-priority indebtedness would take actions that align with the interests of holders of the Notes.

Many of the restrictive covenants contained in the indenture will not apply during any period in which the Notes are rated investment grade by two rating agencies and the holders of the Notes will lose the protection of these covenants during any such periods.

Many of the covenants contained in the indenture will not apply to us during any period in which the Notes are rated investment grade by any two of Moody's Investors Service, Inc., Fitch Ratings, Inc. and Standard & Poor's Ratings Services, provided that at such time no default or event of default has occurred and is continuing. Such covenants will include restrictions on, among other things, our ability to make certain distributions or other restricted payments, incur indebtedness and enter into certain other transactions. There can be no assurance that the Notes will ever be rated investment grade or that if the Notes ever are rated investment grade, they will maintain these ratings. However, suspension of these covenants would allow us to engage in certain transactions that would not be permitted while these covenants were in force. For example, during any such suspension of these covenants, we would be able to make dividends and distributions and incur substantial additional debt in amounts that would not otherwise be permitted while these covenants were in force. To the extent the covenants are subsequently reinstated, any such actions taken while the covenants were suspended would not result in an event of default under the indenture. See "Description of the Notes—Certain Covenants."

Changes in our credit ratings could negatively impact the market price or liquidity of the Notes.

Credit rating agencies continually revise their ratings for the companies that they follow, including us. Credit rating agencies also evaluate our industry as a whole and may change their credit ratings for us based on their overall view of our industry. Additionally, we cannot be sure that credit rating agencies will maintain their ratings on the Notes. A negative change in our ratings could have a negative impact on the future trading prices of the Notes and on our ability to secure future debt financing on commercially reasonable terms or at all.

Our credit ratings could be downgraded.

As of the date of this offering memorandum, our corporate credit rating is "B" from S&P Global Ratings, and "B" from Fitch Ratings, Inc.. Credit ratings are subject to revision, suspension or withdrawal at any time by the assigning rating agency. Rating agencies may also revise or replace entirely the methodology applied to derive credit ratings. We can give no assurances that our credit rating will remain for any period of time or that our credit rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant, or if a different methodology is applied to derive that credit rating.

Any downgrade of one or more of our credit ratings could impact our ability to obtain financing, increase our future financing costs, affect the terms on which suppliers extend us credit, impact our ability to access capital markets and/or have an adverse effect on the trading price of the Notes. A downgrade could also cause the instruments governing any future debt to contain more restrictive covenants, which in turn could limit our ability to obtain additional financing or to respond to changes in business, economic or market conditions.

Service of process, enforcement of judgments and bringing of original actions in the United States, Australia, England and Brazil and other jurisdictions where we have or may in the future have assets may be difficult or impossible.

The Parent Guarantor and certain of the Subsidiary Guarantors are corporations incorporated under the laws of Australia. The Issuer and other Subsidiary Guarantors are corporations incorporated under the laws of Brazil and the U.S. In addition, a majority of our directors, executive officers and managers of each of the Issuer and the Guarantors and certain of the other parties named in this offering memorandum reside outside the United States. A substantial portion of our assets and the assets of these other persons are located outside the United States. As a result, it may be difficult or impossible for you to effect service of process for a lawsuit within the United States upon such persons, including with respect to matters arising under the U.S. Securities Act, or to enforce against any of them judgments in non-U.S. courts obtained in a court of the United States predicated upon, among other things, the civil liability provisions of the U.S. securities laws of the United States or state securities laws. There is doubt as to the enforceability, in original actions in Australian courts, of liabilities predicated solely on the U.S. federal securities laws and as to the enforceability, in Australia. See "Enforcement of civil liabilities."

The Senior Lien Intercreditor Documents, the Second Lien Intercreditor Agreement (if applicable), and certain of the security documents, are governed by the laws of England and Wales. The United States and England and Wales do not have a treaty between them providing for the reciprocal recognition and enforcement of judgments in civil and commercial matters. Consequently, a final judgment for payment rendered by any federal or state court in the United States based on civil liability, whether or not predicated solely upon U.S. federal securities laws, would not automatically be recognized or enforceable in England and Wales. In order to enforce any such U.S. judgment in England and Wales, proceedings must first be initiated before a court of competent jurisdiction in England and Wales. In such an action, an English court would not generally reinvestigate the merits of the original matter decided by the U.S. court (subject to what is said below) and it would usually be possible to obtain summary judgment on such a claim (assuming that there is no good defense to it). Summary judgment is a procedure by which the English court can dispose of all or part of a claim without proceeding to a full trial. Recognition and enforcement of a U.S. judgment by an English court in such an action may be conditional upon (among other things) the following:

- the U.S. court having had jurisdiction over the original proceedings according to English conflicts of laws principles and rules of English private international law (in other words, it does not matter that the U.S. court had jurisdiction according to its own law, but instead whether it had jurisdiction according to the rules of English private international law);

- the U.S. judgment not having been given in breach of a jurisdiction or arbitration clause;

- the U.S. judgment being final and conclusive on the merits in the sense of being final and unalterable in the court which pronounced it and being for a debt for a definite sum of money;

- the U.S. judgment not contravening English public policy or statute in England and Wales;

- the U.S. judgment not being for a sum payable in respect of taxes, or other charges of a like nature, or in respect of a penalty or fine, or otherwise involving the enforcement of a non-English penal or revenue law;

- the recognition and enforcement of the U.S. judgment not being restricted by the provisions of the Protection of Trading Interests Act 1980;

- the U.S. judgment not having been obtained by fraud or in breach of English principles of natural or substantial justice;

- there not having been a prior inconsistent, determinative or conflicting judgment of the courts of England and Wales or another court whose judgment is entitled to recognition in England and Wales;

- the U.S. judgment not having been wholly satisfied or not being enforceable by execution in the U.S.;

- the party seeking enforcement providing security for costs, if ordered to do so by the English court; and

- the English enforcement proceedings being commenced within the relevant limitation period.

Subject to the foregoing, investors may be able to enforce in England and Wales judgments in civil and commercial matters that have been obtained from U.S. federal or state courts. However, we cannot assure you that those judgments will be recognized or enforceable in England and Wales. In addition, it is questionable whether an English court would accept jurisdiction and impose civil liability if proceedings were commenced in England or Wales in an original action predicated solely upon U.S. federal securities laws. Further, it may not be possible to obtain a judgment in England and Wales or to enforce the judgment if the judgment debtor is subject to any insolvency or similar proceedings, of if the judgment debtor has any setoff or counterclaim against the judgment creditor. Finally, in any enforcement proceedings, the judgment debtor may raise any counterclaim that could have been brought if the action had been originally brought in England and Wales unless the subject of the counterclaim was in issue and denied in the U.S. proceedings.

It may be difficult for you to enforce judgments against us or against our directors and executive officers in Brazil.

Pursuant to Brazilian law, judgments of non-Brazilian courts for the payment of money, including for civil liabilities predicated upon the laws of countries other than Brazil, including the U.S. securities laws, subject to certain requirements described below, may be enforced in Brazil. A judgment against either us or any other person described above obtained outside Brazil would be enforceable in Brazil against us or any such person without reconsideration of the merits, upon recognition of that judgment by the Brazilian Superior Court of Justice (*Superior Tribunal de Justiça*). Such recognition, generally, will occur if the foreign judgment: (i) fulfills all formalities required for its enforceability under the laws of the place where it was issued; (ii) is issued by a competent court and/or authority in the jurisdiction where it was awarded, after proper service of process on the parties (if made in Brazil, service of process must be effected in accordance with Brazilian law), or after sufficient evidence of the parties' absence as required by applicable law; (iii) is binding and can be enforced in the jurisdiction in which it was issued; (iv) is effective in the jurisdiction where the decision was issued; (v) is not in conflict with a previous final and binding (res judicata) judgment on the same matter and involving the same parties, cause of action and claim issued in Brazil; (vi) is authenticated by the Brazilian consulate with jurisdiction over the place the judgment is rendered, unless such foreign judgment was authenticated in a country that is signatory of the Hague Convention Abolishing the Requirement of Legalization for Foreign Public Documents dated as of October 5, 1961; (vii) is translated into Portuguese by a certified sworn translator, unless an exemption is provided by an international treaty to which Brazil is a signatory; and (viii) is not contrary to Brazilian national sovereignty or public policy or morality or violate human dignity (as provided in Article 17 of the Law of Introduction to the Brazilian Law in Article 963, VI, of the Brazilian Code of Civil Procedure and in Article 216-F of the Brazilian Superior Court of Justice's Regiment). This recognition process may be time-consuming and may also give rise to difficulties in enforcing the foreign judgment in Brazil. Accordingly, we cannot assure you that the recognition process would be conducted in a timely manner or that a Brazilian court would enforce a monetary judgment for violation of the laws of countries other than Brazil, including the U.S. securities laws. Additionally, (i) civil lawsuits may be brought before Brazilian courts in connection with this offering memorandum based solely on the federal securities laws of the United States and that, subject to applicable law, Brazilian courts may enforce such liabilities in such lawsuits against us (provided that provisions of the federal securities laws of the United States do not contravene Brazilian public policy, good morals or national sovereignty), and provided further that, under Brazilian law, Brazilian courts may assert jurisdiction whenever the defendant is domiciled in Brazil, the obligation has to be performed in Brazil or the subject matter under dispute originates in Brazil, considering that Brazilian courts may exercise jurisdiction over such matters or disputes pursuant to article 88 of the Brazilian Civil Procedure Code; and (ii) the ability of a judgment creditor or the other persons named above to satisfy a judgment by attaching certain assets of tours is limited by provisions of Brazilian bankruptcy, insolvency, liquidation, reorganization or similar laws, given that assets are located in Brazil. However, the application of a foreign body of law by Brazilian courts may be troublesome, as Brazilian courts consistently base their decisions on domestic law or refrain from applying a foreign body of law for a number of reasons. There is a risk that Brazilian courts, considering a relevant case-by-case rationale, may dismiss a petition to apply a foreign body of law and may adopt Brazilian laws to adjudicate the case. In any case, we cannot assure that Brazilian courts will confirm their jurisdiction to rule on such matter, which will depend on the connection of the case to Brazil and, therefore, must be analyzed on a case-by-case basis. A plaintiff (whether Brazilian or non-Brazilian) who resides outside Brazil or is abroad during the course of litigation in Brazil must provide a bond to guarantee the payment of court expenses and defendant's legal fees, if the plaintiff owns no real property in Brazil, that may ensure such payment, except in case of collection claims based on an instrument (which do not include the Notes issued hereunder), that may be enforced in Brazilian courts without the previous review of its merits (*título executivo extrajudicial*) or counterclaims, as established under article 83 of the Brazilian Code of Civil Procedure (Law No. 13,105/2015). The Notes must have a value sufficient to satisfy the payment of court fees and defendant's attorneys' fees, as determined by the Brazilian judge. Furthermore, if proceedings were brought in Brazil seeking to enforce our obligations in respect of the Collateral, we would be required to discharge our obligations only in reais. Under Brazilian exchange controls, an obligation to pay amounts denominated in a currency other than reais, which is payable in Brazil pursuant to a decision of a Brazilian court, will be satisfied in reais at the rate of exchange in effect on the date of payment, as determined by the Central Bank of Brazil. In addition, companies in Brazil may only remit funds out of Brazil and/or convert such funds into hard currency in strict compliance with foreign exchange rules, and there can be no assurance that such companies would have the ability to convert Brazilian real into dollars or euro, nor that such companies would be able to remit such funds out of Brazil.

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

Unless and until certificated notes are issued in exchange for book-entry interests in the Notes, owners of the book-entry interests will not be considered owners or holders of Notes. Instead, DTC, or its nominee, will be the sole holder of the Notes. Payments of principal, interest and other amounts owing on or in respect of the Notes in global form will be made to the paying agent, which will make payments to DTC. Thereafter, such payments will be credited to DTC participants' accounts that hold book-entry interests in the Notes in global form and credited by such participants to indirect participants. Unlike holders of the Notes themselves, owners of book-entry interests will not have the direct right to act upon our solicitations for consents or requests for waivers or other actions from holders of the Notes. Instead, if a holder owns a book-entry interest, such holder will be permitted to act only to the extent such holder has received appropriate proxies to do so from DTC or, if applicable, a participant. We cannot assure holders that the procedures implemented for the granting of such proxies will be sufficient to enable holders to vote on any requested actions on a timely basis.

USE OF PROCEEDS

We estimate that the net proceeds from this offering will be approximately US$343,875,000 after deducting the discounts to the initial purchasers but before deducting the estimated offering expenses payable by us.

We intend to use a portion of the net proceeds of the offering to repay the outstanding amount of US$246.0 million under our RBL facility, which will remain available to be redrawn, and use the remainder of the net proceeds for general corporate purposes, which may include acquisitions.

CAPITALIZATION

The following table sets forth the capitalization of Karoon Energy Limited on:

- a historical consolidated basis as of December 31, 2023; and
- an as adjusted basis to give effect to the receipt of the net proceeds from the Notes offered by this offering memorandum and repayment of a portion of the RBL facility (after deducting the discounts to the initial purchasers but before deducting estimated offering expenses).

After giving effect to the receipt of net proceeds from the Notes offered by this offering memorandum (after deducting the discounts to the initial purchasers but before deducting estimated offering expenses) as described under "Use of proceeds" and below as of December 31, 2023, Karoon Energy Limited would have had US$240.3 million of cash and cash equivalents and US$334.4 million in borrowings.

You should read the following table in conjunction with "Selected consolidated financial data," "Management's discussion and analysis of financial condition and results of operations" and the Karoon Energy financial statements which were audited or reviewed by PricewaterhouseCoopers and included elsewhere in this offering memorandum.

	As of December 31, 2023	
	Actual[1]	**As adjusted[1]**
		(unaudited)
	(US$ million)	
Cash and cash equivalents	**170.4**	**240.3**
Borrowings[1]		
Current borrowings		
Syndicated loan facility – secured	0.1	0.1
Total current borrowings	**0.1**	**0.1**
Non-current borrowings		
Syndicated loan facility – secured	274.0	–
Notes offered hereby	–	350.0
Transaction costs[2]	(9.6)	(15.7)
Total non-current borrowings	**264.4**	**334.3**
Total borrowings	**264.5**	**334.4**
Equity		
Contributed equity	1,210.8	1,210.8
Accumulated losses	(193.3)	(193.3)
Reserves	(103.5)	(103.5)
Total equity	**914.0**	**914.0**
Total capitalization	**1,178.5**	**1,248.4**

Notes:

(1) Borrowings are recognized initially at fair value, net of transaction costs incurred. Subsequent to initial recognition, borrowings are stated at amortized cost. They are not stated at their drawn principal values.

(2) Transaction costs on an as adjusted basis of US$15.7 million includes US$9.6 million of unamortized expenses related to underwriting, legal fees, administrative fees, and any other costs incurred in connection with the RBL facility and an estimated US$6.1 million of discounts to the initial purchasers in connection with the issuance and initial offering of the Notes offered hereby. Transaction costs do not include other estimated expenses of the offering of the Notes, such as legal and accounting expenses.

Since December 31, 2023, we have used cash on hand to repay US$28.1 million of our borrowings under our syndicated loan facilities. Except as disclosed or contemplated in this offering memorandum, there has been no material change in our capitalization since December 31, 2023.

SELECTED CONSOLIDATED FINANCIAL DATA

The income statement and cash flow information for FY21, FY22, FY23, HY23 and TY23 and the balance sheet information as of June 30, 2021, 2022 and 2023 and December 31, 2022 and 2023 have been extracted from our audited consolidated financial statements as of and for the financial years ended June 30, 2022 and 2023 and the transitional financial year ended December 31, 2023 and our unaudited condensed consolidated financial statements for the half-year ended December 31, 2022, in each case included in this offering memorandum, and reflect the consolidated results of operations, cash flows and assets and liabilities of Karoon Energy Limited for such periods.

Our financial statements have been prepared in accordance with the recognition and measurement principles of AAS and IFRS, which differ from US GAAP. You should read the selected consolidated and combined financial data set forth below together with the information in "Financial information presentation," "Risk factors," and "Management's discussion and analysis of financial condition and results of operations" and the Karoon Energy financial statements included elsewhere in this offering memorandum.

Consolidated Statement of Profit or Loss Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Revenue	170.8	385.1	566.5	299.4	412.9
Cost of sales	(111.4)	(191.7)	(283.2)	(148.3)	(164.5)
Gross profit	**59.4**	**193.4**	**283.3**	**151.1**	**248.4**
Other income	0.3	0.8	5.7	1.1	2.6
Business development and other project costs[1]	(17.6)	(3.4)	–	(1.5)	–
Exploration and evaluation expenditure expensed[1]	(3.4)	(3.2)	–	(1.7)	–
Finance costs	(14.4)	(22.7)	(25.4)	(11.7)	(15.9)
Net foreign currency gains/(losses)	(17.1)	6.2	(0.8)	0.3	(8.1)
Other expenses[1]	(28.5)	(33.8)	(41.4)	(20.8)	(41.4)
Change in fair value of contingent consideration	(6.6)	(227.1)	(5.2)	(0.4)	(3.5)
Profit/(loss) before income tax	**(27.9)**	**(89.8)**	**216.2**	**116.4**	**182.1**
Income tax (expense)/benefit	32.3	25.4	(53.2)	(38.8)	(59.6)
Profit/(loss) for the financial period attributable to equity holders of the Company	**4.4**	**(64.4)**	**163.0**	**77.6**	**122.5**

Note:

(1) Prior to TY23, we reported our business development and other project costs and our exploration and evaluation expenditure expensed as separate items on our income statement. In TY23, we included these costs in our other expenses line item, and we reclassified our other expenses for FY23 so that it is presented on the same basis.

Consolidated Statement of Financial Position Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Current assets					
Cash and cash equivalents	133.2	157.7	74.8	163.2	170.4
Receivables	34.2	56.4	73.1	79.3	56.4
Inventories	11.0	19.4	8.7	14.8	18.7
Security deposits	0.2	0.3	–	–	–
Other financial assets	–	–	3.0	–	0.2
Other assets	5.3	11.8	7.6	7.3	6.6
Total current assets	**183.8**	**245.6**	**167.2**	**264.6**	**252.3**
Non-current assets					
Deferred tax assets	36.5	123.0	124.7	125.3	95.2
Inventories	6.5	5.8	8.3	4.5	10.8
Oil and gas assets	736.4	733.0	798.7	813.2	1,391.0
Property, plant and equipment	83	13.3	2.7	2.9	3.1
Intangible assets	0.1	–	0.1	–	0.3
Exploration and evaluation assets	40.9	40.9	85.7	41.3	175.3
Security deposits	1.4	1.3	–	2.4	–
Other financial assets	–	–	–	1.4	–
Other assets	–	1.3	3.0	1.2	4.5
Total non-current assets	**830.1**	**918.6**	**1,023.2**	**992.2**	**1,680.2**
Total assets	**1,014.0**	**1,164.2**	**1,190.4**	**1,256.8**	**1,932.5**
Current liabilities					
Trade and other payables	76.2	68.3	57.2	70.2	68.3
Borrowings	–	–	–	–	0.1
Current tax liabilities	8.3	9.6	5.6	44.8	16.8
Other financial liabilities	–	125.4	86.0	96.1	86.0
Lease liabilities	45.4	43.7	47.2	45.2	48.7
Provisions	0.5	0.4	0.2	0.2	0.2
Total current liabilities	**130.3**	**247.4**	**196.2**	**256.5**	**220.1**
Non-current liabilities					
Trade and other payables	4.3	6.8	5.8	5.6	7.2
Borrowings	–	27.1	28.1	27.6	264.4
Other financial liabilities	71.2	222.0	133.0	214.1	136.5
Deferred tax liabilities	1.8	–	–	–	–
Lease liabilities	267.4	245.2	200.4	222.0	175.7
Provisions	158.8	139.5	153.3	151.9	214.6
Total non-current liabilities	**503.4**	**640.6**	**520.6**	**621.2**	**798.4**
Total liabilities	**633.7**	**888.0**	**716.8**	**877.7**	**1,018.5**
Net assets	**380.3**	**276.2**	**473.6**	**379.1**	**914.0**
Equity					
Contributed equity	905.1	907.5	907.5	907.5	1,210.8
Accumulated losses	(414.4)	(478.8)	(315.8)	(401.2)	(193.3)
Reserves	(110.5)	(152.5)	(118.1)	(127.2)	(103.5)
Total equity	**380.3**	**276.2**	**473.6**	**379.1**	**914.0**

Consolidated Statement of Cash Flows Data

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Cash flows from operating activities					
Receipts from customers	137.0	362.9	552.9	276.7	443.3
Payments to suppliers and employees	(56.5)	(116.5)	(135.2)	(66.8)	(106.2)
Net refunds for Peruvian VAT	4.2	–	–	–	–
Payments for exploration and evaluation expenditure expensed	(15.2)	(3.5)	(4.0)	(1.3)	(3.3)
Payments for Baúna transition expenditure	(15.9)	–	–	–	–
Payments for legal settlement	–	(9.6)	–	–	–
Payments for cash flow hedges	–	(20.8)	(13.4)	(12.7)	(2.7)
Interest received	0.3	–	4.2	1.4	1.0
Borrowing and other costs of finance paid	(13.2)	(18.9)	(19.8)	(9.3)	(9.2)
Income taxes paid	(10.8)	(39.4)	(78.8)	(20.9)	(19.5)
Net cash flows from operating activities	**29.8**	**154.2**	**305.9**	**167.1**	**303.4**
Cash flows from investing activities					
Purchase of plant and equipment and computer software	(4.7)	(5.1)	(2.5)	(2.3)	(0.9)
Acquisition of oil and gas assets	(150.0)	(43.6)	(84.5)	–	(636.8)
Acquisition of exploration and evaluation assets	–	–	–	–	(83.0)
Interest received on deposit	–	–	–	–	0.1
Payments for oil and gas assets	(16.0)	(59.6)	(222.5)	(137.1)	(4.2)
Borrowing costs paid for qualifying assets	(0.2)	(5.8)	(2.7)	(1.7)	–
Payments for exploration and evaluation expenditure capitalized	(1.9)	–	(43.1)	(0.5)	(3.3)
Payment for security deposits	3.6	(0.3)	(0.9)	(0.8)	–
Proceeds from disposal of non-current assets	0.0	1.4	–	–	–
Net cash flows used in investing activities	**(169.2)**	**(113.0)**	**(356.2)**	**(142.4)**	**(728.1)**
Cash flows from financing activities					
Principal elements of lease payments	(23.4)	(44.6)	(34.1)	(19.7)	(19.2)
Proceeds from issue of ordinary shares	–	2.4	–	–	312.3
Payment of equity raising costs	–	–	–	–	(8.8)
Proceeds from borrowings	–	30.0	–	–	274.0
Repayment of borrowings	–	–	–	–	(29.9)
Debt facility costs	–	(3.3)	(0.1)	–	(8.6)
Net cash flows (used in)/from financing activities	**(23.4)**	**(15.5)**	**(34.2)**	**(19.7)**	**519.8**
Net increase/(decrease) in cash and cash equivalents	(162.8)	25.7	(84.5)	5.0	95.1
Cash and cash equivalents at beginning of the period	296.4	133.3	157.7	157.7	74.8
Effect of exchange rate changes on the balance of cash and cash equivalents held in foreign currencies	(0.4)	(1.3)	1.6	0.5	0.5
Cash and cash equivalents at end of the period	**133.2**	**157.7**	**74.8**	**163.2**	**170.4**

SELECTED UNAUDITED PRO FORMA COMBINED FINANCIAL INFORMATION

On December 21, 2023, Karoon Energy Limited ("Karoon", or the "Company") completed the acquisition of a 30% working interest in the Who Dat and Dome Patrol fields, including the associated infrastructure, an approximately 16% working interest in the Abilene field and varying interests in adjacent exploration acreage certain interests in the US Gulf of Mexico (the "Acquired Assets") from LLOG (the "Acquisition"). The consideration for the Acquisition was funded by a drawdown from the RBL facility, an issuance of ordinary shares, and existing cash reserves.

The following unaudited pro forma combined statement of profit or loss for the year ended December 31, 2023 combines the historical unaudited financial results of Karoon for the year ended December 31, 2023 with the historical unaudited statement of revenues and direct operating expenses of the Acquired Assets for the period from January 1, 2023 to December 20, 2023. In July 2023, Karoon changed its fiscal year end from June 30 to December 31. Karoon's unaudited financial results for the year ended December 31, 2023 have been derived from (i) its audited consolidated statement of profit or loss and comprehensive income for the year ended June 30, 2023; (ii) its unaudited condensed consolidated statement of profit or loss and comprehensive income for the six months ended December 31, 2022 and (iii) its audited consolidated statement of profit or loss and comprehensive income for the six months ended December 31, 2023. The unaudited statement of revenues and direct operating expenses of the Acquired Assets for the period from January 1, 2023 to December 20, 2023 have been derived from (i) its audited statement of revenues and direct operating expenses of the Acquired Assets for the year ended December 31, 2023 less (ii) the revenue and direct operating expenses of the Acquired Assets for the period from December 21, 2023 to December 31, 2023 derived from the accounting books and records of Karoon.

The unaudited pro forma combined statement of profit or loss is presented on a pro forma combined basis and gives effect to the Acquisition and the related financing, including A$480 million from the issuance of ordinary shares and a US$274 million drawdown from the RBL facility, as if they occurred on January 1, 2023.

Karoon's historical consolidated financial statements have been prepared in accordance with AAS and also comply with IFRS, as issued by the IASB. The Acquired Assets' historical financial information is based on the statements of revenues and direct operating expenses, which have been prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP") and, for the purposes of the unaudited pro forma combined financial information, have been converted to IFRS on a basis consistent with the accounting policies and presentation adopted by Karoon. Note 1 to the statements of revenues and direct operating expenses included elsewhere in this offering memorandum provides further information regarding the basis of preparation of the statements of revenues and direct operating expenses. The financial statements only represent the net collective working and revenue interests acquired by Karoon, and do not purport to reflect the financial condition or results of operations of the Acquired Assets had such business operated on a stand-alone basis during the periods presented.

The unaudited pro forma combined statement of profit or loss does not include all the information and disclosures required by IFRS for a complete set of financial statements. The unaudited pro forma combined financial information has been derived from and should be read in conjunction with Karoon's consolidated financial statements and the Acquired Assets' statements of revenues and direct operating expenses and related notes, as applicable, and the sections titled "Unaudited pro forma combined financial information," "Risk factors" and "Management's discussion and analysis of financial condition and results of operations" included elsewhere in this offering memorandum.

The pro forma adjustments are transaction accounting adjustments ("Transaction Accounting Adjustments"), which give effect to the Acquisition and drawdown from the RBL facility as if they occurred on January 1, 2023. These adjustments include depreciation and amortization expense that would have been incurred had we owned the Acquired Assets since January 1, 2023 and interest expense that would have been incurred had we drawn US$274 million from the RBL facility on January 1, 2023, as well as a corresponding income tax recovery that would have resulted from these additional expenses. Estimated adjustments have been made to reflect the acquisition method of accounting as required by AAS. We have elected not to present autonomous entity adjustments or management's adjustments and only present the Transaction Accounting Adjustments in the unaudited pro forma combined statement of profit or loss. The Transaction Accounting Adjustments reflected in the unaudited pro forma combined financial information are based on information currently available, assumptions, and estimates underlying the pro forma adjustments and are described in the accompanying notes. Actual results may differ materially from the assumptions used to present the accompanying unaudited pro forma combined financial information. See "Risk factors."

Management believes that the assumptions used to prepare the pro forma combined financial information provide a reasonable basis for presenting the effects of such adjustments and the pro forma combined financial information give appropriate effect to those assumptions and are properly applied in the unaudited pro forma combined financial information. The unaudited pro forma combined financial information is included for informational purposes only and does not purport to reflect the results of operations or financial position that would have occurred had the Acquisition occurred on the assumed acquisition date of January 1, 2023. Accordingly, they should not be relied upon as indicative of our result of operations or financial position had the Acquisition occurred on that assumed acquisition date because, among other reasons, they necessarily exclude various operating expenses and the related income tax effects. Additionally, the unaudited pro forma combined financial information is not a projection of Karoon's results of operations or financial position for any future period to date.

Karoon Energy Limited

Unaudited Pro Forma Combined Statement of Profit or Loss For the year ended December 31, 2023

(in millions of US dollars (US$))

	Karoon for the year ended December 31, 2023 Note 1	Acquired Assets for the period from January 1, 2023 to December 20, 2023 Note 1	Transaction Accounting Adjustments Note 2	Notes	Pro forma combined
Revenue	680.0	147.4	–		827.4
Cost of sales	(299.4)	(27.4)	(76.2)	2(a)	(403.0)
Gross profit	**380.6**	**119.9**	**(76.2)**		**424.3**
Other income	7.2	–	–		7.2
Finance costs	(29.6)	–	(26.0)	2(b)	(55.6)
Net foreign currency gains/(losses)	(9.2)	–	–		(9.2)
Other expenses	(58.8)	–	–		(58.8)
Change in fair value of contingent consideration	(8.3)	–	–		(8.3)
Profit before income tax	**281.9**	**119.9**	**(102.2)**		**299.6**
Income tax expense	(74.0)	–	(4.6)	2(c)	(78.6)
Profit for the financial period attributable to equity holders of the Company	**207.9**	**119.9**	**(106.8)**		**221.0**
Profit per share attributable to equity holders of the Company:					
Basic profit per ordinary share (cents per share)	0.3637			2(d), 3	0.2766
Diluted profit per ordinary share (cents per share)	0.3608			2(d), 3	0.2750

Summary pro forma adjustments, which includes a description of each of the footnotes above, is an integral part of these statements.

Notes to Unaudited Pro Forma Combined Financial Information

1. Basis of presentation

The unaudited pro forma combined financial information has been prepared to illustrate the effect of the Acquisition and has been prepared for informational purposes only.

The unaudited pro forma adjustments are based on information currently available, and assumptions and estimates underlying the unaudited pro forma adjustments are described in the accompanying notes. Actual results may differ materially from the assumptions used to present the accompanying unaudited pro forma combined financial information.

The unaudited pro forma statement of profit or loss for the year ended December 31, 2023 has been prepared using, and should be read in conjunction with, the following:

- Karoon's consolidated statement of profit or loss for the year ended December 31, 2023 which was derived from its audited consolidated statement of profit or loss and comprehensive income for the year ended June 30, 2023 less its unaudited consolidated statement of profit or loss and comprehensive income for the period from July 1, 2022 to December 31, 2022 plus its audited consolidated statement of profit or loss and comprehensive income for the period from July 1, 2023 to December 31, 2023. The audited consolidated financial statements for the period July 1, 2023 to December 31, 2023, audited consolidated financial statements for the year ended June 30, 2023 and the unaudited consolidated financial statements for the period from July 1, 2022 to December 31, 2022, and the related notes are included elsewhere in this offering memorandum; and

- The Acquired Assets' statement of revenues and direct operating expenses for the period from January 1, 2023 to December 20, 2023 which was derived from its audited statement of revenue and direct operating expenses for the year ended December 31, 2023 less the revenue and direct operating expenses of the Acquired Assets for the period from December 21, 2023 to December 31, 2023 which were derived from the accounting books and records of Karoon. The audited statements of revenue and direct operating expenses for the years ended December 31, 2023 and 2022, and the related notes are included elsewhere in this offering memorandum.

The unaudited pro forma combined statement of profit or loss is presented on a pro forma combined basis and gives effect to the Acquisition and the related financing, including A$480 million from the issuance of ordinary shares and a US$274 million drawdown from the RBL facility, as if they occurred on January 1, 2023.

Karoon's historical consolidated financial statements have been prepared in accordance with AAS and also comply with IFRS as issued by the IASB. The historical statement of revenues and direct operating expenses of the Acquired Assets have been prepared in accordance with US GAAP and, for the purposes of the unaudited pro forma combined financial information, have been converted to IFRS on a basis consistent with the accounting policies and presentation adopted by Karoon. There were no adjustments required to convert the Acquired Assets' statement of revenue and direct operating expenses from US GAAP to IFRS.

Karoon's Consolidated Statement of Profit or Loss for the year ended December 31, 2023

	(i) Audited for the year ended June 30, 2023	*Less* (ii) Unaudited for the period from July 1, 2022 to December 31, 2022	*Plus* (ii) Audited for the period July 1, 2023 to December 31, 2023	Unaudited for the year ended December 31, 2023
		(US$ million)		
Revenue	566.5	(299.4)	412.9	680.0
Cost of sales	(283.2)	148.3	(164.5)	(299.4)
Gross profit	**283.3**	**(151.1)**	**248.4**	**380.6**
Other income	5.7	(1.1)	2.6	7.2
Finance costs	(25.4)	11.7	(15.9)	(29.6)
Net foreign currency gains/(losses)	(0.8)	(0.3)	(8.1)	(9.2)
Other expenses	(41.4)	24.0	(41.4)	(58.8)
Change in fair value of contingent consideration	(5.2)	0.4	(3.5)	(8.3)
Profit before income tax	**216.2**	**(116.4)**	**182.1**	**281.9**
Income tax expense	(53.2)	38.8	(59.6)	(74.0)
Profit for the financial period attributable to equity holders of the Company	**163.0**	**(77.6)**	**122.5**	**207.9**

US GAAP to IFRS conversion of the Acquired Assets' Statement of Revenue and Direct Operating Expenses for the period from January 1, 2023 to December 20, 2023

	Historical US GAAP for the year ended December 31, 2023	IFRS Policy	*Less* Historical amounts for the period from December 21, 2023 to December 31, 2023	Historical IFRS for the period from January 1, 2023 to December 20, 2023
		(US$ million)		
Revenues:				
Oil	132.4	–	(4.2)	128.2
Natural gas	16.1	–	(0.5)	15.6
Natural gas liquids	3.6	–	(0.0)	3.6
Total revenues	**152.1**	**–**	**(4.7)**	**147.4**
Direct operating expenses	(30.6)	–	3.2	(27.4)
Revenue less direct operating expenses	**121.4**	**–**	**(1.5)**	**119.9**

The adjustments presented in the unaudited pro forma combined financial information have been identified and presented to provide certain information management considers necessary for an accurate understanding of Karoon after giving effect to the Acquisition. Management has made significant estimates and assumptions in its determination of the pro forma adjustments.

The unaudited pro forma combined financial information is not necessarily indicative of what the actual results of operations would have been had the Acquisition taken place on the dates indicated, nor are they indicative of the future combined results of operations of Karoon after the Acquisition. They should be read in conjunction with the historical financial statements and notes thereto of Karoon and the Acquired Assets. The unaudited pro forma combined financial information does not give effect to any anticipated synergies, operating efficiencies, tax savings, or cost savings that may be associated with the Acquisition. The pro forma adjustments reflecting the consummation of the Acquisition are based on certain currently available information and certain assumptions and methodologies that Karoon believes are reasonable under the circumstances. The assumptions underlying the pro forma adjustments, which are described in the accompanying notes, may be revised as additional information becomes available and is evaluated. Therefore, it is likely that the actual accounting impact of the Acquisition will differ from the pro forma adjustments and it is possible the difference may be material. Karoon believes that these assumptions and methodologies provide a reasonable basis for presenting all of the significant effects of the Acquisition based on information available to management at the time and that the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited pro forma combined financial information.

2. *Pro Forma Adjustments*

Adjustments included in the unaudited pro forma combined financial information are as follows:

(a) Represents the US$76.2 million increase in depreciation and amortization expense computed on a unit of production basis as if the Acquisition were consummated on January 1, 2023. This depreciation and amortization expense was calculated based on the same accounting policy as explained in Note 12 to the Company's audited financial statements for the period ended December 31, 2023.

(b) Reflects the pro forma increase in interest expense of US$26.0 million. This increase represents the interest on the drawings under Karoon's syndicated loan facility to fund the Acquisition as if they had occurred on January 1, 2023. The US$274 million additional indebtedness carries a variable rate of interest. The rate used to estimate the pro forma interest expense was 9.26% based on the prevailing rates at issuance. An increase of 0.125% in the rate assumed would result in an increase interest expense of US$0.3 million in the unaudited pro forma combined statement of profit or loss. This increase in interest expense in each period would cause a corresponding decrease in net income.

(c) Reflects the tax impact of the profit from the Acquired Assets and the Transaction Adjustments at the statutory tax rate of 26% effective in United States. Applying this rate to the sum of the US$76.2 million depreciation and amortization expense described in (a) above and the US$26.0 million interest expense described in (b) above results in a US$26.6 million tax recovery as part of the Transaction Accounting Adjustments.

(d) Reflects increase in number of ordinary shares outstanding as a result of the equity issued to partially fund the Acquisition.

3. *Earnings per share*

Represents the net earnings per share calculated using the historical weighted average shares outstanding, and the issuance of additional 234,343,405 shares in connection with the Acquisition, assuming the shares were outstanding since January 1, 2023. As the Acquisition is being reflected as if it had occurred at the beginning of the period presented, the calculation of weighted average shares outstanding for basic and diluted net earnings per share assumes that the shares issued in connection with the Acquisition have been outstanding for the entire period presented.

4. *Reconciliation of EBITDA and Underlying EBITDA*

The following table shows our EBITDA, Underlying EBITDA reconciled to Karoon's historical consolidated and pro forma combined profit before income tax for the year ended December 31, 2023.

	Year ended December 31, 2023	
	Historical	**Pro Forma**
	(US$ million)	
Profit before income tax	**281.9**	**299.6**
Add back: Depreciation and amortization – oil and gas assets (excluding depreciation on our floating production, storage and offloading facility right of use asset)	98.8	175.0
Add back: Depreciation and amortization – non oil and gas assets	1.0	1.0
Less: Finance income	(5.4)	(5.4)
Add back: Finance costs (excluding interest on our floating production, storage and offloading facility right of use asset)	15.3	41.3
EBITDA	**391.6**	**511.5**
Add back: Restructure costs	–	–
Add back: Change in fair value of contingent consideration	8.3	8.3
Add back: Fair value losses on hedges	8.4	8.4
Add back: Social investments	2.3	2.3
Add back: FX gains/(losses)	9.2	9.2
Add back: Pitkin legal settlement	–	–
Add back: Who Dat acquisition transaction costs	10.8	10.8
Add back: Baúna acquisition transaction costs	–	–
Add back: Inventory impaired	–	–
Less: Writeback of inventory	(1.6)	(1.6)
Underlying EBITDA	**429.0**	**548.9**

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

You should read the following discussion and analysis of our financial position and results of operations together with the selected financial information and consolidated financial statements included elsewhere in this offering memorandum. This section contains forward-looking statements that involve risks, uncertainties and assumptions. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors, including those set out in "Risk factors."

This discussion and analysis is divided into the following sections:

- **Overview** – description of our business and our operating segments, our key income statement line items and a discussion of the key factors affecting our results of operations;
- **Results of operations** – a discussion and analysis of our consolidated results of operations for the transitional financial year ended December 31, 2023 ("TY23") compared to the half-year ended December 31, 2022 ("HY23"), the financial year ended June 30, 2023 ("FY23") compared to the financial year ended June 30, 2022 ("FY22"), and FY22 compared to the financial year ended June 30, 2021 ("FY21");
- **Liquidity and capital resources** – an analysis of our cash flows and sources and uses of cash;
- **Contractual obligations and off-balance sheet arrangements** – a summary of our debt and contractual obligations and our off-balance sheet arrangements;
- **Quantitative and qualitative disclosures about market risk** – disclosures regarding our market risk; and
- **Critical accounting policies –** a discussion of our accounting policies that require critical judgments and estimates.

Overview

Our business

We are an international offshore upstream oil and gas production and exploration company headquartered in Melbourne, Australia, with assets in Brazil and the United States of America. In Brazil, we own and operate the producing Baúna, Piracaba, and Patola fields, which we refer to as Baúna, and are party to concession agreements, in the Santos Basin. In the United States of America, we own non-operated interests in the producing Who Dat, Dome Patrol, and Abilene oil and gas assets, which we refer to as Who Dat, as well as interests in exploration licences, located in the US Gulf of Mexico. Our assets are diversified geographically with multiple producing wells in the Santos Basin and US Gulf of Mexico, which are prolific, globally recognized hydrocarbon basins providing us with the opportunity to increase our reserves and resources. At December 31, 2023, we had production from six oil fields and 19 producing wells, and eight pre-development and exploration blocks.

We have achieved strong growth over the last three and a half years. Our revenue increased from US$170.8 million in FY21 to US$385.1 million in FY22 and to US$566.5 million in FY23. From HY23 to TY23, our revenue increased from US$299.4 million to US$412.9 million. In FY21, FY22, FY23, HY23 and TY23, we achieved profit/(loss) for the financial period attributable to equity holders of the Company of US$4.4 million, US$(64.4) million, US$163.0 million, US$77.6 million and US$122.5 million, respectively. Over those same periods, we recorded and underlying EBITDA of US$61.1 million, US$205.2 million, US$321.8 million, US$175.9 million and US$283.0 million, respectively.

Segments

We identify our operating segments based on the geographical location of our assets. For TY23, we identified our three operating segments to be Australia, Brazil and the USA. We also identified an additional segment which we refer to as "All other segments" which includes amounts of a corporate nature that are not specifically attributable to an operating segment, and we included in this segment the costs associated with the closure of our Peruvian operations. We also recognize and de-recognize operating segments as we divest and acquire assets in new geographies. In FY21, we recognized Peru as an operating segment but did not recognize it in subsequent periods as we relinquished our exploration interests in Peru on July 1, 2021, and in TY23, we recognized USA as an operating segment following our acquisition of asset interests in the Mississippi Canyon Blocks in the US Gulf of Mexico from LLOG Exploration Offshore L.L.C. and LLOG Omega Holdings, L.L.C. (together, "LLOG") on December 21, 2023. In FY22, FY23 and HY23, our three operating segments were Australia, Brazil and our all other segment.

In accordance with AASB 8 *Operating Segments*, we identified these operating segments based on the internal reports that are reviewed and used by our executive management team in assessing performance and the allocation of resources.

Because Brazil was our only significant operating segment for FY21, FY22, FY23, HY23 and TY23, we have not provided further detail regarding our operating segments for these periods in this section. See Note 2, Note 25 and Note 26 to our audited consolidated financial statements for TY23, FY23 and FY22, respectively, for more information about our other operating segments. We expect our USA operating segment to be a significant operating segment in future periods.

Change in fiscal year

Our Board of Directors decided in July 2023 to change our financial year end from June 30 to December 31. This change aligns our financial year with relevant oil and gas industry peers and both Brazil's and the USA's tax years, which we expect will streamline the preparation of our annual financial statements. This change in our financial year end resulted in a transitional financial year consisting of six months that began on July 1, 2023 and ended on December 31, 2023 for which we have prepared audited consolidated financial statements and which we identify as "TY23" in this offering memorandum.

For comparative purposes, we have presented the audited results for TY23 as compared to the unaudited results for HY23 in this section.

Key income statement line items

Revenue

For TY23 and FY23, revenue from oil sales accounted for 99.9% and 100% of our total revenue, respectively. Revenue from gas sales accounted for the remainder of our total revenue for TY23.

We sell the oil we produce from Baúna to Shell Western Supply and Trading Limited, or SWST, under a marketing and offtake agreement. Pursuant to this agreement, SWST markets this oil to a range of customers. This agreement will expire on the later of (i) the date on which we cancel all commitments under our RBL facility, (ii) three years after the end of the "Pre-Existing Term", which is the later of December 9, 2025 or the delivery of 28.6 million barrels of oil pursuant to the agreement, and (iii) when a further 20.0 million barrels of oil have been delivered pursuant to the agreement after the end of the Pre-Existing Term. As of March 31, 2024, 21.9 million barrels of oil have been delivered pursuant to this agreement. We sell all of the oil produced at Baúna at a price equal to the published Brent crude oil price at the time of sale, adjusted for a negotiated price differential and freight logistics and associated costs. Following an amendment to our offtake and marketing agreement with SWST during TY23, SWST may require us to undertake our own oil transportation activities. If this occurs, the freight logistics charges that are netted against our revenue will be reduced, though our cost of sales would increase. See "Business—Our production and exploration assets—Brazil—Producing assets—Baúna—Products, sales, and marketing" for more information about this agreement.

Between December 21, 2023 and March 31, 2024, LLOG sold our share of the oil and gas produced from the Who Dat oil and gas fields on our behalf pursuant to a transitional services agreement. This oil was marketed as Mars grade and sold at a price equal to WTI crude oil as adjusted for the published Mars differential. LLOG sold our share of the gas produced from the Who Dat oil and gas fields off the Platt's Florida Zone 3 or Transco Zone 4 index, both of which are typically at a small premium to the Henry Hub natural gas spot price.

Following the expiry of the transitional services agreement on March 31, 2024, we assumed responsibility for transporting and marketing our share of the oil and gas produced from the Who Dat oil and gas fields. We currently sell our share of crude oil to BP Products North America Inc. under a month-to-month evergreen crude oil purchase agreement at a price equal to the forward price for the following month for WTI crude oil, adjusted for the published Mars differential, a monthly negotiated price differential, transportation costs and a quality adjustment reflecting the quality of the Who Dat crude oil compared to other crude oil transported on the Mars pipeline. We currently sell our share of natural gas on a six-month seasonal contract basis to BP Energy Company under a gas purchase contract at a price equal to the Platt's Florida Zone 3 index, adjusted for a negotiated price differential and the cost of transportation and processing. We sell our share of natural gas liquids under a life-of-asset sales agreement to Williams Field Services, a U.S. based natural gas infrastructure provider, at prices linked to the Mont Belvieu index, as adjusted for the cost of transportation and fractionation. These processing and fractionation costs are paid in kind by the assignment of a percentage of the natural gas liquids processed. We expect to finalize further marketing agreements through 2024, which would give us additional options to optimize sales.

We present our revenues net of all fees and expenses charged by our counterparties under our sales and marketing agreements.

We present the revenue we earn from our Brazilian segment on a gross basis and deduct royalties as part of our cost of sales.

We present the revenue we earn from our USA segment on a net of royalties basis. Because royalties can be taken in kind in the United States, our USA segment revenues are our actual sales less any royalties levied, resulting in lower reported sales volumes and revenue than if we reported on the same basis as our Brazilian segment.

Cost of sales

The major components of our cost of sales are:

- our operating costs;
- for our Brazilian assets, royalties and other government take levied on the production from our producing assets by the relevant government authorities; and
- depreciation and amortization of our oil and gas assets, which includes depreciation associated with the right-of-use component of our *Cidade de Itajaí* floating production, storage and offloading facility charter, which we recognize as a right-of-use asset under AASB 16 *Leases*.

We include in our operating costs our logistics costs, costs under the operating and maintenance contract with OOG-TKP, materials and supplies costs, employee expenses, insurance costs and any other expenses that are directly attributable to our production of oil and gas. Our operating costs are largely fixed in that they are not directly affected by the oil and gas volumes we produce. We also report our unit production costs on a U.S. dollar per barrel of oil equivalent basis, which we calculate by dividing our statutory operating costs plus the costs associated with our floating production, storage and offloading facility charter by our reported production volume. See "—Key operational measures and non-IFRS financial measures—Operational measures—Unit production costs" for the calculation of this measure.

We calculate the depreciation and amortization of our oil and gas assets and the right-of-use component of our floating production, storage and offloading facility charter using the units of production method from the commencement date of production. We initially value the right-of-use asset at cost (i.e. the present value of the related lease liability), and subsequently revalue it at cost less any accumulated depreciation, impairment losses and adjustment for remeasurement of the lease liability. Our floating production, storage and offloading facility charter has a fixed term to February 2026 with renewal options available through 2028. As required by AASB 16, we exercise judgment in determining the lease term for a lease contract that contains a renewal option. As of December 31, 2023, we included the renewal periods as part of the lease term for the purposes of valuing our right-of-use asset. See "—Critical accounting policies—Determining the lease term of contracts with renewal options" for more information about how we exercise this judgment.

We also include in cost of sales the gains or losses associated with the change in our oil and gas inventory during the period.

We may incur transportation costs related to ship-to-ship oil cargo transfers undertaken by us in the Port of Santos, Brazil following an amendment to our marketing and offtake agreement with SWST during TY23.

The following table shows a breakdown of our cost of sales, our reported production volumes and our unit production costs for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
Cost of sales					
Operating costs (US$ million)	38.4	57.2	62.0	30.3	30.2
Royalties and other government take (US$ million)	19.0	41.5	66.7	30.3	45.0
Depreciation and amortization – oil and gas assets (US$ million)	65.0	99.4	143.0	81.7	94.2
Change in inventories (US$ million)	(11.0)	(6.4)	11.5	6.0	(12.7)
Transportation costs (US$ million)	–	–	–	–	7.8
Total cost of sales (US$ million)	111.4	191.7	283.2	148.3	164.5
Reported production volumes (MMboe)	3.14	4.64	7.04	3.37	5.47
Unit production costs[(1)] (US$/bbl)	25.11	25.36	15.75	17.25	11.09

Note:

(1) See "—Key operational measures and non-IFRS financial measures—Operational measures—Unit production costs" for more information about this measure and how we calculate it.

Other income

Other income includes a number of sources of income that we earn outside of oil and gas sales. These include interest income on our financial assets, such as cash and cash equivalents, receivables and security deposits, sundry income and non-cash items such as the write-back of impaired inventory in FY23.

Business development and other project costs

Business development and other project costs consists primarily of the costs and expenses related to our mergers and acquisitions activity. In FY21, these costs also included US$15.7 million of expenses we incurred in transitioning to become an oil operator in connection with our acquisition of Baúna. From and including TY23, we classify our business development and other project costs as part of our other expenses.

Exploration and evaluation expenditure expensed

Exploration and evaluation expenditure expensed reflect the costs we incur and expense in searching for hydrocarbon resources and evaluating the technical feasibility and commercial viability of extracting the resources we identify. We account for exploration and evaluation expenditure expensed using the 'successful efforts' method of accounting. We expense all exploration and evaluation expenditure in relation to an area of interest in the period in which we incur them, other than the cost of successful wells, the costs of acquiring interests in new exploration assets, and appraisal costs relating to determining development feasibility, which we capitalize as exploration and evaluation assets. For exploration wells, we initially capitalize the costs associated with drilling the wells on a well-by-well basis pending the evaluation of whether potentially economic reserves of hydrocarbons have been discovered. We will expense these capitalized costs if no recoverable hydrocarbons are identified. See "—Critical accounting policies—Capitalized exploration and evaluation expenditure" for more information about the judgments we make in capitalizing exploration and evaluation assets.

From and including TY23, we classify exploration and evaluation expenditure expensed as part of our other expenses.

Finance costs

Our finance costs predominantly relate to finance charges on our lease liabilities and the unwinding of the discount that has been applied when calculating the net present value of our restoration provisions. Our finance costs also include interest expenses and other finance charges related to our RBL facility.

Finance charges on lease liabilities

Most of our finance charges on lease liabilities relate to our floating production, storage and offloading facility charter at Baúna.

We initially value a lease liability on its commencement date at the present value of the lease payments we expect to pay over the lease term, discounted using the interest rate implicit in the lease or, if the rate cannot be readily determined, our estimated incremental borrowing rate. We subsequently increase our lease liability by the interest cost, which we recognize as a finance charge on our income statement, and decrease it by any lease payments made. We will also remeasure the lease liability if our estimated future lease payments change as a result of index or rate changes, residual value guarantees or a change in the likelihood of exercise of purchase, extension or termination options. Our floating production, storage and offloading facility charter has a fixed term to February 2026 with renewal options available through 2028. As required by AASB 16, we exercise judgment in determining the lease term for a lease contract that contains a renewal option. As of December 31, 2023, we included the renewal periods as part of the lease term for the purposes of valuing our lease liability. See "—Critical accounting policies—Determining the lease term of contracts with renewal options" for more information about this judgment.

Discount unwinding

We recognize a provision for our restoration obligations on our balance sheet. We calculate this provision by discounting to present value our estimated future restoration obligations, which include the estimated costs of decommissioning and removing an asset and restoring the site. We unwind this discount monthly as we approach the relevant asset's end-of-life, and we recognize the effect of this unwinding as an accretion charge within our finance costs. See "—Critical accounting policies—Provision for restoration" for more information about how we calculate our restoration provisions.

Interest expense

Prior to March 2023, we capitalized the majority of our interest payments under our then-existing debt facilities as a development asset and recognized the remainder as an interest expense. Following the completion of the Patola development in March 2023, we reclassified this development as a production asset from April 2023. Following this reclassification, we now expense all interest payments under our borrowings (including under our RBL facility).

Other finance costs

We include in our other finance costs any commitment fees we pay under our debt facilities and the amortization of capitalized financing costs. Consistent with the treatment of interest expense described above, we now fully expense our financing costs from April 2023.

We also include in other finance costs the write-off of any unamortized transaction costs related to loan facilities that are prepaid and canceled ahead of their stated maturity.

The following table shows a breakdown of our finance costs for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Finance costs					
Finance charges on lease liabilities	12.5	16.9	15.5	8.0	6.8
Discount unwinding on net present value of provision for restoration	0.9	2.4	5.0	2.1	3.2
Interest expense	1.0	2.1	2.1	0.4	2.5
Other finance costs	–	1.3	2.8	1.2	3.4
Total finance costs	14.4	22.7	25.4	11.7	15.9

Net foreign currency gains/(losses)

Our functional and financial statement presentation currency is the U.S. dollar, and the majority of our revenues and expenses are denominated in U.S. dollars. However, our administrative and business development expenditures are incurred in Australian dollars, while a portion of our operating and capital expenditures related to our Baúna production assets are incurred in Brazilian real. We translate these transactions into the U.S. dollar using the foreign exchange rates prevailing at the dates of the transactions, and we recognize foreign currency gains and losses from the settlement of these transactions in our income statement. We also translate monetary assets and liabilities denominated in foreign currencies using the financial period end exchange rates and recognize any associated gain or loss in our income statement.

Other expenses

The major components of our other expenses are:

- corporate expenses;
- realized gains/losses on cash flow hedges;
- legal and commercial settlements; and
- share-based payments expense.

Our corporate expenses include net employee expenses, consulting expenses, insurance costs, travel costs, director fees and other expenses.

As of December 31, 2023, we recognized our Brent crude oil price hedges as a cash flow hedging instrument. Our realized gains/losses on cash flow hedges represent the amount that we are in/out of the money on the oil hedges that expire during the period and the amortization of our hedge premiums. Our hedges are in/out of the money when the Brent crude oil price is below/above the bought put option strike price or above/below the sold call option strike price, respectively.

When we designate a derivative as a cash flow hedging instrument, we immediately recognize the ineffective portion of the change in fair value of the derivative in our income statement. The ineffective portion is the amount that we do not expect to offset the change in cash flows of the hedged item or transaction. We recognized no losses for hedge ineffectiveness during TY23 and FY23.

Our share-based payments expense reflects the fair value of the performance rights granted to our executive directors and employees and the change in fair value of our cash-settled share-based payments.

Our other expenses also include expenditure on social investments/sponsorships, which are payments in lieu of corporate income tax which is allowable under Brazilian tax law. There is no effect on our profit/(loss) because of these payments as these amounts replace tax payable.

From and including TY23, we include our business development and other project costs and our exploration and evaluation expenditure expensed within other expenses. We classified these expenses separately in prior periods.

We also reported as part of our other expenses our advisory and transaction costs in relation to the acquisition of interests in the Who Dat assets from LLOG.

The following table shows a breakdown of our other expenses for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Other expenses					
Advisory and transaction costs	–	–	–	–	10.8
Business development and other project costs(1)	–	–	3.7	–	0.7
Exploration and evaluation expenditure expensed(1)	–	–	3.9	–	3.3
Corporate	12.3	15.4	20.7	9.2	14.0
Realized losses on cash flow hedges	–	11.8	7.1	7.2	8.5
Legal settlement	9.6	–	–	–	–
Depreciation and amortization – non-oil and gas assets	0.7	0.7	0.9	0.4	0.5
Share-based payments expense	4.9	5.7	3.1	2.1	1.4
Social investments/sponsorships	–	–	1.9	1.8	2.2
Loss on disposal of non-current assets	–	–	0.1	0.1	–
Write-down of inventory to net realizable value	0.6	–	–	–	–
Other expenses	0.5	0.2	–	–	–
Total other expenses	28.5	33.8	41.4	20.8	41.4

Note:

(1) Prior to TY23, we reported our business development and other project costs and our exploration and evaluation expenditure expensed as separate items on our income statement. In TY23, we included these costs in our other expenses line item, and we reclassified our other expenses for FY23 so that it is presented on the same basis. In FY21, FY22 and HY23, our business development and other project costs were US$17.6 million, US$3.4 million and US$1.5 million, respectively, and our exploration and evaluation expenditure expensed were US$3.4 million, US$3.2 million and US$1.7 million, respectively.

Change in fair value of contingent consideration

We recognize the change in the fair value of our contingent consideration arrangement in our income statement.

We agreed to pay Petrobras contingent consideration of up to US$285 million plus interest of 2% per annum accruing from January 1, 2019 as part of our acquisition of Baúna. We account for the fair value of this consideration by calculating the present value of the future expected cash outflows. Our estimates are based on our internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts. We re-assess the fair value of this arrangement semi-annually and will record any increase or decrease in fair value as an expense or revenue, respectively, in our income statement. See "—Key factors affecting our results—Fair value adjustments for contingent consideration" for more information about how we calculate the fair value of this contingent consideration arrangement.

Income tax (expense)/benefit

Income tax (expense)/benefit represents the amount of income tax payable or receivable in relation to our profit or loss before tax for the year and any deferred tax. See "—Critical accounting policies—Income tax" for more information about how we calculate deferred tax assets and liabilities. We conduct a foreign exchange translation adjustment monthly on our deferred tax balances using the foreign exchange rates prevailing at the period end date and recognize any movements on our deferred tax balances in our income statement. Most of our income tax expense is recognized in relation to our operations in Australia and Brazil, where the corporate income tax rate is 30% and 34%, respectively. In the USA, we are subject to the federal corporate income tax rate of 24%. Under our current sales agreements, the point of sale for our production is offshore, which means that the resulting revenue is not subject to state taxes. If we sell our products onshore, we may be subject to income taxes in the state or states in which they are sold. We also recognize income tax in the other jurisdictions in which we operate.

Key operational measures and non-IFRS financial measures

We use a number of operational measures and non-IFRS financial measures to assess the financial and operational performance of our business. We believe these operational measures and non-IFRS measures provide useful information about our business and our management considers these measures in analyzing our operating and financial performance. The measures set forth below should be considered in addition to, not as a substitute for or in isolation from, our financial results prepared in accordance with AAS which also comply with IFRS.

Operational measures

Unit production costs

Unit production costs is a measure of the costs directly attributable to our revenue-generating operations on a per barrel of oil equivalent produced basis. We calculate our unit production costs by dividing our statutory operating costs plus the costs associated with our floating production, storage and offloading facility charter by our reported production volumes. The numerator used in this calculation is different from how we calculate our statutory cost of sales, which includes the depreciation and amortization and lease interest related to our floating production, storage and offloading facility right-of-use asset and related lease liability (both of which are capitalized in accordance with AASB 16 *Leases*), respectively. The following tables show how we calculate our unit production costs for FY21, FY22, FY23, HY23, TY23 and for the year ended December 31, 2023 ("CY23"). We also show our *pro forma* unit production costs for CY23 as if we had acquired our share in the Who Dat assets on January 1, 2023.

	FY21			
Unit production costs	**Reported**	**Back out AASB 16**	**Cost of production-related leases**	**Unit production costs**
Operating costs (US$ million)	38.4	–	–	38.4
Capitalized lease(s) depreciation & amortization (US$ million)	28.1	(28.1)	–	–
Capitalized lease(s) interest (US$ million)	12.4	(12.4)	–	–
Cost of lease(s) (US$ million)	–	–	40.5	40.5
Total costs (US$ million)	78.9	(40.5)	40.5	78.9
Reported production volumes (MMboe)	3.14	3.14	3.14	3.14
Unit production costs/boe	25.11	(12.89)	12.89	25.11

Unit production costs	FY22 Reported	FY22 Back out AASB 16	FY22 Cost of production-related leases	FY22 Unit production costs
Operating costs (US$ million)	57.2	–	–	57.2
Capitalized lease(s) depreciation & amortization (US$ million)	44.4	(44.4)	–	–
Capitalized lease(s) interest (US$ million)	16.8	(16.8)	–	–
Cost of lease(s) (US$ million)	–	–	60.4	60.4
Total costs (US$ million)	118.3	(61.2)	60.4	117.6
Reported production volumes (MMboe)	4.64	4.64	4.64	4.64
Unit production costs/boe	25.51	(13.19)	13.03	25.36

Unit production costs	FY23 Reported	FY23 Back out AASB 16	FY23 Cost of production-related leases	FY23 Unit production costs
Operating costs (US$ million)	62.0	–	–	62.0
Capitalized lease(s) depreciation & amortization (US$ million)	57.5	(57.5)	–	–
Capitalized lease(s) interest (US$ million)	15.3	(15.3)	–	–
Cost of lease(s) (US$ million)	–	–	48.8	48.8
Total costs (US$ million)	134.9	(72.9)	48.8	110.8
Reported production volumes (MMboe)	7.04	7.04	7.04	7.04
Unit production costs/boe	19.17	(10.36)	6.94	15.75

Unit production costs	HY23 Reported	HY23 Back out AASB 16	HY23 Cost of production-related leases	HY23 Unit production costs
Operating costs (US$ million)	30.3	–	–	30.3
Capitalized lease(s) depreciation & amortization (US$ million)	34.2	(34.2)	–	–
Capitalized lease(s) interest (US$ million)	8.0	(8.0)	–	–
Cost of lease(s) (US$ million)	–	–	27.8	27.8
Total costs (US$ million)	72.5	(42.2)	27.8	58.2
Reported production volumes (MMboe)	3.37	3.37	3.37	3.37
Unit production costs/boe	21.50	(12.51)	8.25	17.25

Unit production costs	TY23 Reported	TY23 Back out AASB 16	TY23 Cost of production-related leases	TY23 Unit production costs
Operating costs (US$ million)	30.2	–	–	30.2
Capitalized lease(s) depreciation & amortization (US$ million)	33.4	(33.4)	–	–
Capitalized lease(s) interest (US$ million)	6.8	(6.8)	–	–
Cost of lease(s) (US$ million)	–	–	30.4	30.4
Total costs (US$ million)	70.5	(40.2)	30.4	60.6
Reported production volumes (MMboe)	5.47	5.47	5.47	5.47
Unit production costs/boe	12.89	(7.36)	5.56	11.09

	CY23						
	Historical				Pro Forma		
Unit production costs	**Reported**	**Back out AASB 16**	**Cost of production-related leases**	**Unit production costs**	**Remove 11 days Who Dat contribution**	**Add 12 months abbreviated financials**	**Unit production costs**
Operating costs (US$ million)	61.9	–	–	61.9	(0.64)	21.9	83.16
Capitalized lease(s) depreciation & amortization (US$ million)	56.7	(56.7)	–	–	–	–	–
Capitalized lease(s) interest (US$ million)	14.1	(14.1)	–	–	–	–	–
Cost of lease(s) (US$ million)	–	–	51.4	51.4	–	–	51.4
Total costs (US$ million)	132.7	(70.8)	51.4	113.3	(0.64)	21.9	134.56
Reported production volumes (MMboe)	9.14	9.14	9.14	9.14	(0.09)	2.78	11.8
Unit production costs/boe	14.52	(7.75)	5.62	12.40	(7.09)	7.88	11.38

Weighted average realized sale price

We calculate our weighted average realized oil and gas price (net of selling expenses) for each period by dividing our reported revenue for that period by the amount of barrels of oil equivalent sold in that period.

Our reported sales volumes and production volumes may differ in a given period as we may not sell all of the volumes produced, primarily due to the timing of our oil cargoes, and we may sell volumes produced in the prior period.

The following table summarizes our historical reported sales volumes and revenue for FY21, FY22, FY23, HY23 and TY23.

	FY21	**FY22**	**FY23**	**HY23**	**TY23[(1)]**
Reported revenue (US$ million)	170.8	385.1	566.5	299.4	412.9
Reported sales volumes (MMboe)	2.90	4.54	7.06	3.41	5.07
Weighted average realized oil and gas price (net of selling expense) (US$/boe)	59.00	84.74	80.20	87.86	81.51

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following the completion of our acquisition.

Non-IFRS financial measures

EBITDA and underlying EBITDA

We define EBITDA as our earnings before interest, tax, depreciation, depletion and amortization (but including the depreciation and interest on our floating production, storage and offloading facility right of use asset). We present underlying EBITDA as our EBITDA as adjusted for several non-cash items and other expenses that we believe are not representative of our underlying performance. Consistent with market practice, we include the depreciation and interest on our floating production, storage and offloading facility right of use asset when calculating our EBITDA. The following table presents a reconciliation of EBITDA and underlying EBITDA for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Profit before income tax	**(27.9)**	**(89.8)**	**216.2**	**116.4**	**182.1**
Add back: Depreciation and amortization – oil and gas assets (excluding depreciation on our floating production, storage and offloading facility right of use asset)	36.8	55.0	85.5	47.5	60.8
Add back: Depreciation and amortization – non oil and gas assets	0.7	0.7	0.9	0.4	0.5
Less: Finance income	(0.3)	(0.2)	(4.0)	(1.1)	(2.5)
Add back: Finance costs (excluding interest on our floating production, storage and offloading facility right of use asset)	2.1	5.9	9.9	3.7	9.1
EBITDA	**11.4**	**(28.4)**	**308.5**	**166.9**	**249.9**
Add back: Restructure costs	–	0.9	–	–	–
Add back: Change in fair value of contingent consideration	6.6	227.1	5.2	0.4	3.5
Add back: Fair value losses on hedges	–	11.8	7.1	7.2	8.5
Add back: Social investments	–	–	1.9	1.8	2.2
Add back: FX (gains)/losses	17.1	(6.2)	0.8	(0.3)	8.1
Add back: Pitkin legal settlement[(1)]	9.6	–	–	–	–
Add back: Who Dat acquisition transaction costs	–	–	–	–	10.8
Add back: Baúna acquisition transaction costs	15.8	–	–	–	–
Add back: Inventory impaired	0.6	–	–	–	–
Less: Writeback of inventory	–	–	(1.6)	–	–
Underlying EBITDA	**61.1**	**205.2**	**321.8**	**175.9**	**283.0**

Note:

(1) This settlement related a dispute regarding an alleged breach of our exploration obligations in connection with Block Z-38, offshore Peru.

EBITDA and underlying EBITDA are non-IFRS financial measures derived from our financial statements and associated accounting books and records. We present these as a supplemental measure of our performance. EBITDA and underlying EBITDA should not be considered as an alternative to profit before tax or any other measure of financial performance calculated and presented in accordance with IFRS. EBITDA and underlying EBITDA are presented because they are key metrics used by our management to assess our financial performance. We present EBITDA and underlying EBITDA as we believe they provide further insight into the performance of our business and our ability to meet our debt service requirements.

EBITDA and underlying EBITDA have limitations as an analytical tool and investors should not consider it in isolation from, or as a substitute for, our results of operations. Some of the limitations of EBITDA and underlying EBITDA are that: (i) they do not reflect our cash expenditures or future requirements for capital expenditure or contractual commitments; (ii) they do not reflect changes in, or cash requirements for, our working capital needs; (iii) they do not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments in respect of any borrowings; (iv) although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA and underlying EBITDA do not reflect that any cash amortized will often have to be replaced in the future, and EBITDA and underlying EBITDA do not reflect any cash requirements for such replacements; (v) other companies in our industry may calculate EBITDA and underlying EBITDA differently from how we calculate them, limiting their usefulness as a comparative measure; and (vi) they do not reflect gains and losses in foreign exchange rates, which may impact earnings.

Net debt/(cash)

We define our net debt/(cash) as our total borrowings (excluding transaction costs) less cash and cash equivalents. The following table sets forth our calculation of net debt/(cash) as of June 30, 2021, 2022 and 2023 and as of December 31, 2022 and 2023.

	As of June 30,			As of December 31,	
	2021	2022	2023	2022	2023
			(US$ million)		
Total borrowings	–	30.0	30.0	30.0	274.1
Cash and cash equivalents	(133.2)	(157.7)	(74.8)	(163.2)	(170.4)
Net debt/(cash)	**(133.2)**	**(127.7)**	**(44.8)**	**(133.2)**	**103.7**

Gearing ratio

We define our gearing ratio as our net debt divided by net debt plus equity. The following table sets forth our calculation of our gearing ratio as of June 30, 2021, 2022 and 2023 and as of December 31, 2022 and 2023. As our net debt was negative as of June 30, 2021, 2022 and 2023 and as of December 31, 2022, we have not presented our gearing ratio for those dates as we do not believe it to be meaningful.

	As of June 30,			As of December 31,	
	2021	2022	2023	2022	2023
Net debt/(cash) (US$ million)	(133.2)	(127.7)	(44.8)	(133.2)	103.7
Equity (US$ million)	380.3	276.2	473.6	379.1	914.0
Gearing ratio	**N/A**	**N/A**	**N/A**	**N/A**	**10.2%**

Net interest expense/(income)

We define our net interest expense/(income) as our interest expense minus our interest income. The following table sets forth our calculation of our net interest expense/(income) for FY21, FY22, FY23 and the last twelve months to December 31, 2023.

	FY21	FY22	FY23	Twelve months to December 31, 2023
		(US$ million)		
Interest expense	1.0	2.1	2.1	4.2
Interest income	(0.3)	(0.2)	(4.0)	(5.4)
Net interest expense/(income)	**0.7**	**1.9**	**(1.9)**	**(1.2)**

Interest cover ratio

We define our interest cover ratio as our underlying EBITDA divided by our net interest expense. The following table sets forth our calculation of our interest cover ratio for FY21, FY22, FY23 and the last twelve months to December 31, 2023. As we had a net interest income in FY23 and the twelve months to December 31, 2023, we have not presented our interest cover ratio for those periods as we do not believe it to be meaningful.

	FY21	FY22	FY23	Twelve months to December 31, 2023
Underlying EBITDA (US$ million)	61.1	205.2	321.8	428.9
Net interest expense (US$ million)	0.7	1.9	(1.9)	(1.2)
Interest cover ratio	**87.29x**	**108.00x**	**N/A**	**N/A**

Leverage ratio

We define our leverage ratio as our net debt divided by our underlying EBITDA. The following table sets forth our calculation of our leverage ratio for FY21, FY22, FY23 and the last twelve months to December 31, 2023. As our net debt was negative as of June 30, 2021, 2022 and 2023, we have not presented our leverage ratio for those dates as we do not believe the metric to be meaningful for FY21, FY22, FY23.

	FY21	FY22	FY23	Twelve months to December 31, 2023
Net debt/(cash) (US$ million)	(133.2)	(127.7)	(44.8)	103.7
Underlying EBITDA (US$ million)	61.1	205.2	321.8	428.9
Leverage ratio	**N/A**	**N/A**	**N/A**	**0.24x**

Key factors affecting our results

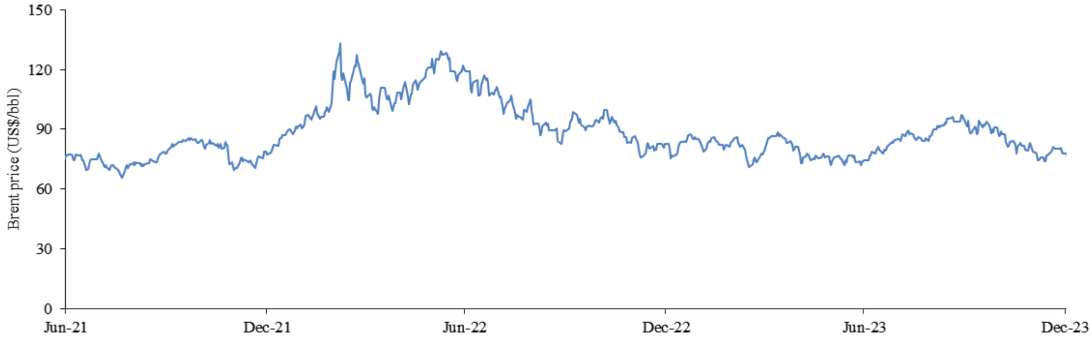
The most significant factors affecting our results of operations are our production volumes and the prices at which we sell our production, which are predominantly set by reference to global oil prices and, to a lesser extent, local gas prices. These factors influence our results of operations both directly, through the amount of revenue we receive and our cost of sales, and indirectly, through the carrying value of our assets and the impact on our hedging book.

Oil and gas prices

Almost all of our revenues are exposed to global oil prices through contract prices that are set by reference to either the Brent crude oil price or the WTI crude oil price. See "—Key income statement line items—Revenue" for more information about the terms under which we sell our oil production. During TY23 and FY23, 100% of our oil sales volumes were sold under terms linked to global oil prices, while 100% of our gas volumes were sold under terms linked to local gas prices during TY23. During TY23, we sold approximately 99% of our oil sales volumes under contracts with pricing set by reference to the Brent crude oil price.

Factors affecting oil prices include worldwide oil supply and demand, the level of economic activity in the markets we serve as well as general worldwide economic conditions, regional political developments and military conflicts in oil producing countries and regions (in particular, Russia/Ukraine), the weather, the ability of the OPEC+ and other producing regions (including North America) to influence global production levels and prices, the price and availability of new technology, the availability and cost of alternative sources of energy and legal and regulatory developments.

Oil and gas prices increased to above pre-pandemic levels in 2021 as a result of increasing COVID-19 vaccination rates and loosening pandemic-related restrictions, triggering an increase in overall demand, and the output limitations implemented by OPEC. In the first half of 2022, the prices for oil and gas increased substantially as a result of underinvestment in new supply, which was exacerbated by Russia's invasion of Ukraine and the international sanctions imposed on Russia as a consequence. In the second half of 2022, the prices for oil declined but remained above pandemic levels, while spot prices for gas remained at near record levels until October 2022 when prices fell due to a warmer than expected Northern hemisphere winter resulting in comfortable storage inventories. In 2023, oil prices decreased to below 2022 averages but still remained elevated when compared to historical levels due to ongoing supply restrictions implemented by OPEC+, the impacts of which were partially offset by economic headwinds. These headwinds included monetary tightening by reserve banks around the world, a high inflationary cost environment, the risk of a U.S. debt default and rising geopolitical tensions in the Middle East. Gas prices also fell significantly when compared to 2022 prices and were slightly depressed when compared to historical levels due to a warm Northern hemisphere winter and the increased uptake of renewable energy sources. In 2024 to date, oil prices decreased to slightly below 2023 averages primarily due to economic headwinds such as the persistently high inflationary cost environment, reduced oil demand, and continuing geopolitical tensions in the Middle East. These headwinds more than offset the ongoing supply restrictions implemented by OPEC+. Gas prices also fell below 2023 prices due to the increased uptake of other energy sources and a warm Northern hemisphere winter. The following chart illustrates the Brent crude oil prices in U.S. dollars per barrel from June 30, 2021 to December 31, 2023.



The following table sets forth our average realized oil price (net of selling expenses) and average realized gas price (net of selling expenses) for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
Weighted average realized oil price (net of selling expenses) (US$ per barrel)	59.00	84.74	80.20	87.86	81.96
Weighted average realized gas price (net of selling expenses)[1] (US$ per scf)	N/A	N/A	N/A	N/A	2.2

Note:

(1) We began selling gas on December 21, 2023 after completing the acquisition of the Who Dat assets.

Under our RBL facility, we are required to enter into hedging arrangements to mitigate our exposure to movements in oil prices by reference to a minimum proportion of our forecast production from our borrowing base assets at the relevant time on a rolling two-year basis. The amount we are required to hedge is determined by our collateral coverage ratio at each testing date. We are prohibited from hedging more than 70% of our forecast production over the next two years under our RBL facility. We re-assess our hedging requirements every six months. For more information about our RBL facility, see "Description of other financing arrangements." The table below sets forth our minimum hedging requirements over the following 6, 12, 18 and 24 months as determined by reference to our collateral coverage ratio as of each testing date.

	Minimum hedging requirements on forecast production over the next			
	6 months	12 months	18 months	24 months
Collateral coverage ratio as of each testing date				
Less than or equal to 1.25x	40.0%	30.0%	23.0%	17.0%
Greater than 1.25x and less than or equal to 1.67x	30.0%	23.0%	17.0%	–
Greater than 1.67x and less than or equal to 2.5x	23.0%	17.0%	–	–
Greater than 2.5x and less than or equal to 5.0x	17.0%	–	–	–
Greater than 5.0x	–	–	–	–

As of December 31, 2023, our collateral coverage ratio was 1.0x. See "Description of other financing arrangements—Reserve based lending facility—Covenants and undertakings—Hedging" for a discussion of how we calculate our collateral coverage ratio.

The following table summarizes our hedging arrangements as of December 31, 2023 and June 30, 2023, 2022 and 2021.

As of December 31,	Volume hedged ('000 bbl)	Details of hedges
2023	630 bought put options 423 sold call options	630,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in 2024. 423,000 barrels hedged using sold call options with a strike price of US$98.00 per barrel with an expiry date in 2024.

As of June 30,	Volume hedged ('000 bbl)	Details of hedges
2023	2,040 bought put options 1,578 sold call options	2,040,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in 2024. 630,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in 2024. 947,520 barrels hedged using sold call options with a strike price of US$98.00 per barrel with an expiry date in 2024.
2022	2,946 bought put options 2,946 sold call options	2,316,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in FY23. 630,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in 2024. 426,000 barrels hedged using sold call options with a strike price of US$87.50 per barrel with an expiry date in FY23. 1,890,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in FY23. 630,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in 2024.

As of June 30,	Volume hedged ('000 bbl)	Details of hedges
2021	3,940 bought put options 3,940 sold call options	994,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in FY22. 2,316,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in FY23. 630,000 barrels hedged using bought put options with a strike price of US$65.00 per barrel with an expiry date in 2024. 994,000 barrels hedged using sold call options with a strike price of US$87.50 per barrel with an expiry date in FY22. 426,000 barrels hedged using sold call options with a strike price of US$87.50 per barrel with an expiry date in FY23. 1,890,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in FY23. 630,000 barrels hedged using sold call options with a strike price of US$82.50 per barrel with an expiry date in 2024.

Since December 31, 2023, we have entered into further hedging arrangements in accordance with our obligations under the RBL facility. The following table summarizes the hedging arrangements we have entered into since December 31, 2023.

Calendar year	Volume hedged ('000 bbl)	Details of hedges
2024	2,695 bought put options 2,695 sold call options	1,300,000 barrels hedged using bought put options with a strike price of US$62.00 per barrel with an expiry date in 2024. 1,395,000 barrels hedged using bought put options with a strike price of US$60.00 per barrel with an expiry date in 2024. 2,695,000 barrels hedged using sold call options with a strike price of US$92.00 per barrel with an expiry date in 2024.
2025	1,569 bought put options 1,569 sold call options	1,569,000 barrels hedged using bought put options with a strike price of US$58.00 per barrel with an expiry date in 2025. 1,569,000 barrels hedged using sold call options with a strike price of US$92.00 per barrel with an expiry date in 2025.

Changes in oil prices can also have an indirect effect on our estimates of oil reserves and the carrying value of our assets. See "Reserves", "—Oil and gas reserves" and "—Critical accounting policies—Estimates of reserves quantities" for more information.

Movements in oil prices may also impact the fair value of our contingent consideration obligations. For more information, see "—Fair value adjustments for contingent consideration."

Production volume

From period to period, our production volume is affected by the following main factors:

- natural variability in the production volume of oil and gas fields, which typically 'ramp up' to a peak production level shortly after coming online and then decline over time;
- acquisitions and disposals of interests in producing assets;
- production interruptions (including at wellhead, subsea and other gathering infrastructure), which may be planned (for example, for maintenance, refits or upgrades) or unplanned, including plant or equipment failures and natural disasters such as severe hurricanes and earthquakes; and
- well workover programs on existing oil and gas wells to enhance, restore or maintain their productivity.

During TY23 and the three years ended June 30, 2023, the major factors that affected our production were:

- the acquisition of the Baúna oil fields on November 6, 2020 from Petrobras, which produced 3.14 MMbbl during FY21;
- the shutdown of the *Cidade de Itajaí* floating production, storage and offloading facility between March 28, 2023 and May 8, 2023, resulting in no oil production during this period;
- the three well Baúna workover program which completed in late 2022, which added more than 9,200 bopd on average (excluding the shut-down period) throughout the remainder of FY23;
- the Patola development which achieved first oil on March 15, 2023, which added more than 16,500 bopd on average (excluding the shut-down period) throughout the remainder of FY23; and
- operational issues relating to equipment in the gas-lift dehydration unit on the floating production, storage and offloading facility in late 2023 which compromised production at two of our wells at Baúna (SPS-56 and SPS-88), which we estimate reduced our total production in TY23 by approximately 0.3 MMboe.

On December 21, 2023, we acquired interests in the Who Dat assets from LLOG. While these assets only contributed 0.09 MMboe to our production volumes in TY23, we expect these assets to be a major contributor to our production volumes going forward.

Since December 31, 2023, we have remediated the issues relating to equipment on our floating production, storage and offloading facility that impacted production at one of our wells at Baúna (SPS-88). We have been unable to resume normal production at SPS-88 due to what we believe is a mechanical blockage in the well's gas lift valve. We expect to undertake a workover program in an attempt to return the well to normal production in the fourth quarter of 2024, subject to regulatory approvals and securing appropriate equipment. In conjunction with the operator of the floating production, storage and offloading facility, we are also planning a full shut-down of our operations on the floating production, storage and offloading facility to undertake planned maintenance from mid to late May 2024, and we expect production to resume in early June 2024.

The following tables summarize our historical reported production volumes by asset and by product for FY21, FY22, FY23, HY23 and TY23.

Reported production volume by assets

	For the twelve months ended June 30,			For the six months ended December 31,	
	2021	**2022**	**2023**	**2022**	**2023**[1]
Baúna (MMbbl)	3.14	4.64	7.04	3.37	5.38
Who Dat[1] (MMboe)	–	–	–	–	0.09
Total (MMboe)	3.14	4.64	7.04	3.37	5.47

Note:

(1) Includes our share in the Who Dat assets on a net revenue interest basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Reported production volume by product

	For the twelve months ended June 30,			For the six months ended December 31,	
	2021	**2022**	**2023**	**2022**	**2023**[1]
Oil (MMbbl)	3.14	4.64	7.04	3.37	5.44
Gas[1] (MMboe)	–	–	–	–	0.03
Total (MMboe)	3.14	4.64	7.04	3.37	5.47

Note:

(1) Includes our share in the Who Dat assets on a net revenue interest basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Royalties and other government take

We are required to pay royalties, special participation fees and research and development levies to the Brazilian government on an ongoing basis.

The Brazilian National Agency for Petroleum, Natural Gas and Biofuels ("ANP") determines the monthly royalty rate to be applied to each concession block. This rate ranges from 5% to 10% of the gross notional revenue (defined as production volume multiplied by the published ANP reference price) from that block, and the ANP will consider the block's geological risks and the expected production, among other factors, in determining the royalty rate.

In October 2022, we were granted a reduction in the royalty rate applied to our incremental production from Baúna pursuant to a Brazilian regulatory regime that incentivizes the ongoing development of mature oil and gas fields. The reduced royalty rate applies to all incremental production from Baúna resulting from the Baúna workover campaign and the Patola field development. For our incremental production up to 50% above the base production profile at Baúna, a royalty rate of 7.5% will apply. For incremental production higher than 50% above the base production profile, a royalty rate of 5% will apply. These reduced royalty rates applied from October 2022.

We are required to pay special participation fees when our quarterly production is in excess of 300,000 m^3 or 1.9 million barrels. We are also required to pay a research & development levy equal to 1% of gross notional revenue in the quarters that we are required to pay special participation fees. The special participation fee is calculated through progressive rates that vary according to the location, lifetime of the field, and production volumes, pursuant to applicable regulations. The special participation fee related to each field is payable on a quarterly basis from the date the high production occurred and is calculated based on the gross notional revenue of each field, less: (i) operational expenses and depreciation in the current quarter; and (ii) any special participation fees and research and development levies paid in the prior period.

In addition, the Brazilian government imposed a temporary crude oil export tax that had effect between March 1, 2023 and June 30, 2023. This scheme levied a 9.2% tax on all of our sales volumes during that period.

For our USA segment, we pay a 12.50% royalty on the value of our share of production from the Who Dat oil and gas fields to the Office of Natural Resources Revenue. In addition, we pay royalties in connection with specific leases to third parties under agreements with prior interest holders. For example, certain limited zones of block MC 502, on which the Who Dat field is partly located, are subject to a 5% overriding royalty stemming from a farm-out agreement with Eni Petroleum US LLC. See "Regulatory overview—Regulatory overview—Brazil—Concession bids—Government participation" and "Regulatory overview—Regulatory overview—Gulf of Mexico—Other oil and gas industry regulations" for more information about the royalty regimes that apply to us.

The following table sets out the royalties and other government take for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Royalties and other government take					
Royalties	19.0	41.5	47.3	27.5	32.0
Special participation tax	–	–	1.4	1.1	8.7
R&D obligations	–	–	3.4	1.7	4.3
Export tax	–	–	14.6	–	–
Total	19.0	41.5	66.7	30.3	45.0

Oil and gas reserves

We rely on our reserves estimates in assessing items such as our asset carrying values, restoration provisions and deferred tax balances. We prepare our reserves estimates in accordance with PRMS 2018 and the ASX listing rules. Our estimates are based on:

- our interpretation of geological and geophysical models;
- reservoir engineering and production engineering analyses and models; and
- assessments of the technical feasibility and commercial viability of producing the reserves.

Our reserves assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes, all of which are constantly changing. These assumptions in turn influence the economic recoverability of our oil and gas resources and, therefore, what proportion of resources we recognize as reserves. Our reserves estimates may also change as additional geological data is generated through the course of operations. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources" for more information about our reserves estimates.

Any increase or decrease in our reserves estimates could lead to higher or lower depreciation and/or amortization charges or the immediate write-down of the carrying value of assets (in the event of a decrease in reserves). We immediately recognize the impact of such changes in our income statement for that period. See "Risk factors—Risks relating to our industry and operations—Interim and annual reviews of our reserves and resources may result in reserve and resource write-downs, us recognizing impairments in the carrying value of our assets or changing our development plans" for more information about the potential impact of reserves write-downs.

Exploration and evaluation activities

Our ability to continue as an oil and gas producer is significantly influenced by our ability to identify and develop new oil and gas fields.

We are involved in a number of exploration, appraisal and evaluation activities, including the Neon discovery and geological and geophysical studies at four other exploration tenements in the Santos Basin. The Who Dat joint ventures are involved in exploration and evaluation activities on four exploration tenements in the US Gulf of Mexico. On April 3, 2024, the respective joint venture partners approved the drilling of an appraisal well and an exploration well in Who Dat East and Who Dat South, respectively, and we expect the total cost of the two wells to us to be between US$67 million and US$77 million. We also monitor and evaluate acreage acquisition opportunities potentially available to us through Brazilian regulatory release cycles.

These exploration and evaluation activities may require significant levels of capital in order for us to determine the development feasibility of these tenements. The success or failure of our exploration, appraisal and evaluation activities will affect the level of reserves and resources we recognize and our future development plans for a particular licensed area. Failed exploration and evaluation activities will also increase the exploration expense we recognize in a reporting period. See "—Key income statement line items—Exploration and evaluation expenditure expensed" and "—Critical accounting policies—Capitalized exploration and evaluation expenditure" for more information about how we expense and capitalize exploration expenditure.

The following table sets forth our exploration and evaluation expenses during FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Exploration and evaluation expenditure expensed(1)	3.4	3.2	3.9	1.7	3.3

Note:

(1) Prior to TY23, we reported our exploration and evaluation expenditure expensed as a separate item on our income statement. In TY23, we included these costs in our other expenses line item, and we reclassified our other expenses for FY23 so that it is presented on the same basis.

The following table sets forth our capitalized exploration and evaluation expenses as of December 31, 2023 and 2022 and June 30, 2023, 2022 and 2021. The increase in our capitalized exploration and evaluation expenditure between June 30, 2023 and December 31, 2023 was primarily due to the acquisition of the Who Dat assets.

	As of June 30,			As of December 31,	
	2021	2022	2023	2022	2023
Capitalized exploration and evaluation expenditure	40.9	40.9	85.7	41.3	175.3

Fair value adjustments for contingent consideration

We agreed to pay Petrobras contingent consideration of up to US$285 million plus interest of 2% per annum accruing from January 1, 2019 as part of our acquisition of Baúna. We account for the fair value of this consideration by calculating the present value of the future expected cash outflows.

The payment of this contingent consideration is dependent on future oil prices each calendar year from 2022 to 2026 inclusive, and we are required to begin making payments when the annual average Platts Dated Brent oil prices threshold is above US$50 a barrel. The contingent consideration payable does not depend on the volume of production from the Baúna assets nor the price at which the oil is actually sold. We test the annual average Platts Dated Brent oil prices annually. After testing, any amounts we deem not payable in that calendar year will be canceled and not carried forward. Any payments that are required to be made are paid in January of the subsequent year. The following table sets out the amount payable each calendar year (in US$ millions and excluding interest) depending on the average Brent crude oil price as described below.

	2022	2023	2024	2025	2026
Average Brent crude oil price (in US$ units)					
Less than US$50	–	–	–	–	–
From and including US$50 to US$55	3	3	3	2	2
From and including US$55 to US$60	17	17	17	8	4
From and including US$60 to US$65	34	34	34	15	6
From and including US$65 to US$70	53	53	53	24	10
Above and including US$70	78	78	78	36	15

Based on our FY22 internal forecasts, which align with our current internal forecasts, we have assumed that the average Brent crude oil prices from 2022 through 2026 will exceed the US$70 per barrel threshold such that we would have to pay the maximum amount of contingent consideration under this arrangement for each calendar year from 2022 through to 2026. This led to us recognizing the present value of the entire contingent consideration arrangement in FY22. Should forecast prices stay above the US$70 per barrel threshold, any other fair market value adjustments we will make to the contingent consideration arrangement will be as a result of a change in the discount rate used to calculate the present value of this arrangement. Should the forecast average Brent crude oil prices drop below the US$70 per barrel threshold at subsequent testing dates for future calendar years, we will revise the fair value of the contingent consideration arrangement accordingly to reflect the new present value of the contingent consideration arrangement.

For FY22, the average Brent crude oil price exceeded US$70, and as a result we paid US$84.5 million to Petrobras in consideration for our acquisition of Baúna in FY23. For FY23, the average Brent crude oil price exceeded US$70, and as a result we paid US$86.0 million to Petrobras in consideration for our acquisition of Baúna in January 2024. Although these payments are reflected in our cash flows for those periods, they are not reflected in our income statement for those periods as fair value adjustments for the present value of those payments was reflected in FY22.

Currency exchange movements

We report our financial results in U.S. dollars, which is the functional currency of our operations in Brazil and the USA.

Our revenue, significant operating expenditure (including the floating production, storage and offloading facility charter) and a large component of capital obligations are predominantly denominated in U.S. dollars. Our foreign exchange risk exposures primarily relate to our corporate overheads and business development expenditures which are incurred in Australian dollars and a portion of our operating and capital expenditures related to our Baúna production assets and the payment of Brazilian taxes which are incurred in Brazilian real. We translate our foreign currency transactions into U.S. dollars using the foreign exchange rates prevailing at the dates of the transactions, and we recognize foreign currency gains and losses from the settlement of these transactions in our income statement. As a result, increases in the value of the Australian dollar and Brazilian real relative to the U.S. dollar increase our costs and reduce our profit and vice versa.

Results of operations

TY23 compared to HY23

Our results for TY23 included 11 days of results from the Who Dat assets. As such, readers should exercise caution in comparing our results for TY23 with HY23.

Consolidated results

We increased production from Baúna materially in TY23 compared to HY23 following completion of the Baúna workover program and Patola field development during FY23. This production increase, while partially offset by decreased oil prices in TY23 compared to HY23, led to our gross profit increasing US$97.3 million, or 64.4%, from US$151.1 million in HY23 to US$248.4 million in TY23. Our EBITDA increased US$83.0 million, or 49.7%, from US$166.9 million to US$249.9 million, and our profit for the financial period attributable to equity holders of the Company increased US$44.9 million, or 57.9%, from US$77.6 million to US$122.5 million.

The following table sets out our consolidated income statement for HY23 and TY23.

	HY23	TY23
	(US$ million)	
Revenue	299.4	412.9
Cost of sales	(148.3)	(164.5)
Gross profit	**151.1**	**248.4**
Other income	1.1	2.6
Business development and other project costs	(1.5)	–
Exploration and evaluation expenditure expensed	(1.7)	–
Finance costs	(11.7)	(15.9)
Net foreign currency gains/(losses)	0.3	(8.1)
Other expenses[1]	(20.8)	(41.4)
Change in fair value of contingent consideration	(0.4)	(3.5)
Profit before income tax	**116.4**	**182.1**
Income tax expense	(38.8)	(59.6)
Profit for financial period attributable to equity holders of the Company	**77.6**	**122.5**

Note:

(1) Includes US$0.7 million of business development and other project costs and US$3.3 million of exploration and evaluation expenditure expensed for TY23.

Revenue

Our reported revenue increased US$113.5 million, or 37.9%, from US$299.4 million for HY23 to US$412.9 million for TY23. This increase was primarily due to our reported oil sales increasing 1.7 MMboe, or 48.4%, from 3.4 MMboe to 5.1 MMboe as a result of the completion of the Baúna workover program in late 2022 and the Patola development in March 2023, partially offset by a number of minor operational issues. The impact of this sales volume increase was partially offset by our weighted average realized oil and gas price (net of selling expenses) decreasing US$6.35 per barrel of oil equivalent, or 7.2%, from US$87.86 per barrel of oil equivalent to US$81.51 per barrel of oil equivalent due to decreases in oil prices. Our Who Dat assets contributed US$3.9 million in reported revenue and 0.1 MMboe in reported sales volumes in TY23.

Cost of sales

Our cost of sales increased US$16.2 million, or 10.9%, from US$148.3 million for HY23 to US$164.5 million for TY23. This increase was primarily due to our royalties and other government take expense increasing US$14.7 million, or 48.5%, from US$30.3 million to US$45.0 million due to our increased oil production and the application of special participation fees, partially offset by the ANP reducing the royalty rate applied to incremental production from Baúna with effect from October 2022. Depreciation and amortization on our oil and gas assets also increased US$12.5 million, or 15.3%, from US$81.7 million to US$94.2 million due to the increase in our oil production, partially offset by the increase in our 2P reserves primarily due to the completion of the Patola development in March 2023. This increase in cost of sales was partially offset by an increase in inventories of US$12.7 million in TY23 as compared to a decrease in inventories of US$6.0 million in HY23. Our operating costs were flat between TY23 and HY23, with an increase in materials and supplies costs and logistics costs as a result of increased production volumes being offset by decreased insurance costs and decreased costs related to our operating and maintenance contract. As a result of the increased production and our largely fixed operating cost base, our unit production costs fell US$6.16 per barrel of oil equivalent, or 35.7%, from US$17.25 per barrel of oil equivalent to US$11.09 per barrel of oil equivalent. The cost of sales associated with our Who Dat assets was US$2.5 million in TY23.

Other income

Our other income increased US$1.5 million, or 136.4%, from US$1.1 million for HY23 to US$2.6 million for TY23. This increase was primarily due to our interest income increasing US$1.4 million, or 127.3%, from US$1.1 million to US$2.5 million primarily due to higher U.S. dollar interest rates and larger cash balances.

Business development and other project costs

Our business development and other project costs decreased US$0.8 million, or 53.3%, from US$1.5 million in HY23 to US$0.7 million in TY23. In TY23, we included our business development and other project costs within other expenses. We classified these expenses separately in our income statement for HY23.

Exploration and evaluation expenditure expensed

Our exploration and evaluation expenditure expensed increased US$1.6 million, or 94.1%, from US$1.7 million in HY23 to US$3.3 million in TY23, primarily due to increased exploration activity at the Neon discovery block. In TY23, we included our exploration and evaluation expenditure expensed within other expenses. We classified these expenses separately in our income statement for HY23.

Finance costs

Our finance costs increased US$4.2 million, or 35.9%, from US$11.7 million in HY23 to US$15.9 million in TY23. This increase was primarily driven by increases in our other finance costs, interest expenses and the discount unwinding on net present value of the provision for restoration. Our other finance costs increased US$2.2 million from US$1.2 million to US$3.4 million primarily due to the payment of a US$1.6 million commitment fee under our RBL facility alongside other transaction costs related to the RBL facility. As a result of us reclassifying the Patola development as a production asset in 2023, we now fully expense the interest expenses under our debt facilities, which was the primary driver behind our interest expense increasing US$2.1 million from US$0.4 million to US$2.5 million. Our discount unwinding on net present value of the provision for restoration increased US$1.1 million, or 52.4%, from US$2.1 million to US$3.2 million due to an increased pre-tax discount rate being applied to our restoration provisions in the prior financial year and the recognition of a restoration provision related to our Patola production asset. This increase in finance costs was partially offset by a decrease in finance charges on lease liabilities of US$1.2 million, or 15.0%, from US$8.0 million to US$6.8 million primarily due to the remeasurement of our lease liabilities following the operational issues at our floating production, storage and offloading facility in late 2023.

Net foreign currency gains/(losses)

We recorded a net foreign currency loss of US$8.1 million for TY23, compared to a net foreign currency gain of US$0.3 million for HY23. This change was primarily due to a US$9.9 million hedging loss we recognized on the settlement of our Australian dollar denominated equity raise in TY23.

Other expenses

Our other expenses increased US$20.6 million, or 99.0%, from US$20.8 million in HY23 to US$41.4 million in TY23. This increase was primarily due to us incurring advisory and transaction costs of US$10.8 million in TY23 in connection with the acquisition of the Who Dat assets compared to US$0 in HY23. An increase in corporate expenses of US$4.8 million, or 52.2%, from US$9.2 million to US$14.0 million, primarily due to increased consulting expenses, employee expenses and IT expenses, also contributed to this increase. In TY23, we included our business development and other project costs and our exploration and evaluation expenditure expensed within other expenses. We classified these expenses separately in our income statement for HY23. These expenses totaled US$4.0 million in TY23. See "—Business development and other project costs" and "—Exploration and evaluation expenditure expensed" above for more information about how these line items impacted our results of operations for TY23 and HY23.

Change in fair value of contingent consideration

Change in the fair value of our contingent consideration obligation for Baúna was a loss of US$3.5 million in TY23 compared to a loss of US$0.4 million in HY23. These losses were due to us increasing the fair value of the contingent consideration arrangement in each period as a result of a change in the discount rate used.

Income tax expense

Our income tax expense increased US$20.8 million, or 53.6%, from US$38.8 million in HY23 to US$59.6 million in TY23. Our current income tax decreased US$26.5 million, or 50.2%, from US$52.8 million to US$26.3 million primarily due to the tax benefits of accelerated depreciation and interest on net equity in TY23. Our deferred income tax expense increased US$47.3 million from a benefit of US$14.0 million to an expense of US$33.3 million, primarily due to a US$48.6 million expense recognized against temporary differences in the deferred tax balance we recognized for the depreciation of our oil and gas assets, partially offset by a US$12.8 million income tax benefit we received for temporary differences in our right-of-use assets.

FY23 compared to FY22

Consolidated results

We increased production from Baúna materially in FY23 following completion of the Baúna workover program and Patola field development. This production increase, while partially offset by decreased oil prices in FY23 compared to FY22, led to our gross profit increasing US$89.9 million, or 46.5%, from US$193.4 million in FY22 to US$283.3 million in FY23. Our financial performance in FY22 was also impacted by a US$227.1 million loss we recognized due to an increase in the fair value of our contingent consideration obligation due to Petrobras for the Baúna acquisition due to increases in expected future oil prices which resulted in the present value of the maximum contingent amount being recognized. As a result, our EBITDA was a loss of US$28.4 million in FY22 compared to a gain of US$308.5 million in FY23, and our profit for the financial period attributable to equity holders of the Company was US$163.0 million in FY23, compared to a loss for the financial period attributable to equity holders of the Company of US$64.4 million in FY22.

The following table sets out our consolidated income statement for FY22 and FY23.

	FY22	FY23
	(US$ million)	
Revenue	385.1	566.5
Cost of sales	(191.7)	(283.2)
Gross profit	**193.4**	**283.3**
Other income	0.8	5.7
Business development and other project costs	(3.4)	–
Exploration and evaluation expenditure expensed	(3.2)	–
Finance costs	(22.7)	(25.4)
Net foreign currency gains/(losses)	6.2	(0.8)
Other expenses[1]	(33.8)	(41.4)
Change in fair value of contingent consideration	(227.1)	(5.2)
Profit/(loss) before income tax	**(89.8)**	**216.2**
Income tax (expense)/benefit	25.4	(53.2)
Profit/(loss) for financial period attributable to equity holders of the Company	**(64.4)**	**163.0**

Note:

(1) Includes US$3.7 million of business development and other project costs and US$3.9 million of exploration and evaluation expenditure expensed for FY23.

Revenue

Reported revenue increased US$181.4 million, or 47.1%, from US$385.1 million for FY22 to US$566.5 million for FY23. This revenue increase was primarily due to our oil sales increasing 2.6 MMbbl, or 57.8%, from 4.5 MMbbl to 7.1 MMbbl as a result of the completion of the Baúna workover program in late 2022 and the Patola development in March 2023, partially offset by the 6 week shutdown in production activities after a leak in the gas flare system of the floating production, storage and offloading facility was identified. The impact of this sales volume increase was partially offset by our weighted average realized oil price (net of selling expenses) decreasing US$4.54 per barrel, or 5.4%, from US$84.74 per barrel to US$80.20 per barrel due to decreases in oil prices.

Cost of sales

Cost of sales increased US$91.5 million, or 47.7%, from US$191.7 million for FY22 to US$283.2 million for FY23. This increase in cost of sales was primarily due to depreciation and amortization on our oil and gas assets increasing US$43.6 million, or 43.9%, from US$99.4 million to US$143.0 million due to the increase in our oil production and our larger asset base following the completion of the Baúna workover program and the Patola development. Royalties and other government take expenses also increased US$25.2 million, or 60.7%, from US$41.5 million to US$66.7 million due to our increased oil production, increased special participation fees and the introduction of a temporary crude oil export tax, which led to an export tax of US$14.6 million, partially offset by the ANP reducing the royalty rate applied to incremental production from Baúna with effect from October 2022. As a result of the increased production and our largely fixed operating cost base, our unit production costs fell US$9.61 per barrel, or 37.9%, from US$25.36 per barrel to US$15.75 per barrel.

Other income

Other income increased US$4.9 million, or 612.5%, from US$0.8 million for FY22 to US$5.7 million for FY23. This increase was primarily due to our interest income increasing from US$0.2 million to US$4.0 million primarily due to higher U.S. dollar interest rates.

Business development and other project costs

Business development and other project costs increased US$0.3 million, or 8.8%, from US$3.4 million for FY22 to US$3.7 million for FY23. We included our business development and other project costs within other expenses in FY23 in our audited consolidated financial statements for TY23. We classified these expenses separately in our income statement for FY22.

Exploration and evaluation expenditure expensed

Exploration and evaluation expenditure expensed increased US$0.7 million, or 21.9%, from US$3.2 million for FY22 to US$3.9 million for FY23. This increase was primarily due to increased spend at the Neon discovery block. We included our exploration and evaluation expenditure expensed within other expenses in FY23 in our audited consolidated financial statements for TY23. We classified these expenses separately in our income statement for FY22.

Finance costs

Finance costs increased US$2.7 million, or 11.9%, from US$22.7 million for FY22 to US$25.4 million for FY23. This increase in finance costs was primarily due to our discount unwinding on net present value of provision for restoration increasing US$2.6 million, or 108.3%, from US$2.4 million to US$5.0 million due to an increased pre-tax discount rate being applied to our restoration provisions and the recognition of a restoration provision related to our Patola production asset. An increase in other finance costs of US$1.5 million, or 115.4%, from US$1.3 million to US$2.8 million, primarily due to the payment of a US$1.6 million commitment fee under our RBL facility alongside other transaction costs related to the RBL facility, also contributed to the increase in finance costs. This increase in finance costs was partially offset by a decrease in finance charges on lease liabilities of US$1.4 million, or 8.3%, from US$16.9 million to US$15.5 million due to the remeasurement of our lease liabilities following the shutdown of the floating production, storage and offloading facility.

Net foreign currency gains/(losses)

We recorded a net foreign currency loss of US$0.8 million for FY23, compared to a net foreign currency gain of US$6.2 million for FY22. This change was due to the Brazilian real appreciating in value against the U.S. dollar as compared to the prior period.

Other expenses

Our other expenses increased US$7.6 million, or 22.5%, from US$33.8 million in FY22 to US$41.4 million in FY23. We included our business development and other project costs and our exploration and evaluation expenditure expensed within other expenses in FY23 in our audited consolidated financial statements for TY23. We classified these expenses separately in our income statement for FY22. These expenses totaled US$7.6 million in FY23. See "—Business development and other project costs" and "—Exploration and evaluation expenditure expensed" above for more information about how these line items impacted our results of operations for FY23 and FY22. Excluding the impact of these items on our other expenses, our other expenses would have remained stable between the periods. Our corporate expenses increased US$5.3 million, or 34.4%, from US$15.4 million to US$20.7 million primarily due to increased headcount in Brazil and wage inflation. Meanwhile, our realized losses on cash flow hedges decreased US$4.7 million, or 39.9%, from US$11.8 million to US$7.1 million due to lower oil prices and our share-based payments expense decreased US$2.6 million, or 45.6%, from US$5.7 million to US$3.1 million primarily due to the non-recurrence of share-based payments that were made to outgoing executives in FY22.

Change in fair value of contingent consideration

Change in the fair value of our contingent consideration obligation for Baúna was a loss of US$5.2 million for FY23 compared to a loss of US$227.1 million for FY22. We recognized a change in fair value in FY23 as we made a revision to the discount rate used to calculate the fair value of the contingent consideration arrangement. We recognized the amount in FY22 as we revised our internal Brent crude oil forecast, based on higher oil prices and industry consensus, to be above the US$70 per barrel threshold above which we are required to pay the full amount of the contingent consideration to Petrobras.

Income tax (expense)/benefit

We recognized an income tax expense of US$53.2 million for FY23 compared to an income tax benefit of US$25.4 million for FY22. Our current income tax increased US$34.7 million, or 88.3%, from US$39.3 million to US$74.0 million, primarily due to the profit before income tax we earned during FY23 as compared to the loss before income tax during FY22. A decrease in deferred income tax benefit of US$43.9 million, or 67.9%, from US$64.7 million to US$20.8 million also contributed to our increased income tax expense in FY23. This decrease in deferred income tax benefit was primarily due to the non-recurrence of a tax benefit of US$77.2 million related to our contingent consideration expense during FY22, partially offset by an income tax benefit we received of US$24.6 million due to the appreciation of the Brazilian real against the U.S. dollar during FY23.

FY22 compared to FY21

Our results for FY22 reflect a full financial year of operating the assets acquired from Petrobras, whereas our results for FY21 only reflect such operations from November 7, 2020. As such, readers should exercise caution in comparing our results for the two periods.

Consolidated results

Our gross profit increased US$134.0 million, or 225.6%, from US$59.4 million in FY21 to US$193.4 million in FY22. As noted in "—FY23 compared to FY22—Consolidated results", our financial performance in FY22 was impacted by a US$227.1 million loss we recognized as a result of the increase in the fair value of our contingent consideration obligation for Baúna. As a result, our EBITDA was US$11.4 million in FY21 compared to a loss of US$28.4 million in FY22. We recorded a loss for the financial period attributable to equity holders of the Company of US$64.4 million in FY22, as compared to a profit for the financial period attributable to equity holders of the Company of US$4.4 million in FY21.

The following table sets out our consolidated income statement for FY21 and FY22.

	FY21	FY22
	(US$ million)	
Revenue	170.8	385.1
Cost of sales	(111.4)	(191.7)
Gross profit	**59.4**	**193.4**
Other income	0.3	0.8
Business development and other project costs	(17.6)	(3.4)
Exploration and evaluation expenditure expensed	(3.4)	(3.2)
Finance costs	(14.4)	(22.7)
Net foreign currency gains/(losses)	(17.1)	6.2
Other expenses	(28.5)	(33.8)
Change in fair value of contingent consideration	(6.6)	(227.1)
Profit/(loss) before income tax	**(27.9)**	**(89.8)**
Income tax benefit	32.3	25.4
Profit/(loss) for financial period attributable to equity holders of the Company	**4.4**	**(64.4)**

Revenue

Reported revenue increased US$214.3 million, or 125.5%, from US$170.8 million for FY21 to US$385.1 million for FY22. This increase was due to our weighted average realized oil price (net of selling expenses) increasing US$25.74 per barrel, or 43.6%, from US$59.00 per barrel to US$84.74 per barrel due to increased oil prices and our reported sales volume increasing 1.6 MMbbl, or 56.5%, from 2.9 MMbbl to 4.5 MMbbl, reflecting our first full year of operating Baúna since acquiring it on November 7, 2020 and high levels of operational uptime.

Cost of sales

Cost of sales increased US$80.3 million, or 72.1%, from US$111.4 million for FY21 to US$191.7 million for FY22. The increase in cost of sales was primarily due to depreciation and amortization on our oil and gas assets increasing US$34.4 million, or 52.9%, from US$65.0 million to US$99.4 million, due to the increase in our oil production. Royalties and other government take expenses also increased US$22.5 million, or 118.4%, from US$19.0 million to US$41.5 million due to our increased oil production. In addition, our operating costs increased US$18.8 million, or 49.0%, from US$38.4 million to US$57.2 million primarily due to us operating Baúna for a full year. Primarily due to us operating Baúna for a full year and associated ramp-up costs, our unit production costs increased US$0.25 per barrel from US$25.11 per barrel to US$25.36 per barrel.

Other income

Other income increased US$0.5 million, or 166.7%, from US$0.3 million for FY21 to US$0.8 million for FY22.

Business development and other project costs

Business development and other project costs decreased US$14.2 million, or 80.6%, from US$17.6 million for FY21 to US$3.4 million for FY22. This decrease was primarily due to non-recurrence of transaction and transition costs we incurred in FY21 in connection with the Baúna acquisition.

Exploration and evaluation expenditure expensed

Exploration and evaluation expenditure expensed decreased US$0.2 million, or 5.9%, from US$3.4 million for FY21 to US$3.2 million for FY22.

Finance costs

Finance costs increased US$8.3 million, or 57.6%, from US$14.4 million for FY21 to US$22.7 million for FY22. This increase in finance costs was primarily due to our finance charges on lease liabilities increasing US$4.4 million, or 35.2%, from US$12.5 million to US$16.9 million due to us leasing the floating production, storage and offloading facility for a full financial year and the increase in interest rates. An increase in the discount unwinding on net present value of provision for restoration of US$1.5 million, or 166.7%, from US$0.9 million to US$2.4 million primarily due to the discount rate applied to these provisions increasing, also contributed to the increase in finance costs.

Net foreign currency gains/(losses)

We recorded a net foreign currency gain of US$6.2 million for FY22 compared to a net foreign currency loss of US$17.1 million for FY21. This change was primarily due to the U.S. dollar appreciating in value against the Australian dollar and Brazilian real.

Other expenses

Other expenses increased US$5.3 million, or 18.4%, from US$28.5 million for FY21 to US$33.8 million for FY22. This increase in other expenses was primarily due to us recognizing realized losses on cash flow hedges of US$11.8 million in FY22 as compared to US$0 in FY21 due to an increase in global oil prices. This increase in other expenses was partially offset by the non-recurrence of a US$9.6 million payment we made in FY21 to settle a dispute regarding an alleged breach of our exploration obligations in connection with Block Z-38, offshore Peru.

Change in fair value of contingent consideration

Change in the fair value of our contingent consideration obligation for Baúna increased US$220.5 million from a loss of US$6.6 million for FY21 to a loss of US$227.1 million for FY22. We recognized a significant increase in the fair value of the contingent consideration obligation to Petrobras in FY22 as we revised our internal Brent crude oil forecast, based on higher oil prices and industry consensus, to be above the US$70 per barrel threshold, above which we are required to pay the full amount of the contingent consideration to Petrobras.

Income tax benefit

Income tax benefit decreased US$6.9 million, or 21.3%, from US$32.3 million for FY21 to US$25.4 million for FY22. Our current income tax increased US$24.0 million, or 156.5%, from US$15.3 million to US$39.3 million, reflecting the increase in our pre-tax profitability excluding the impact of the increase in the fair value of our contingent consideration arrangement. This increase in income tax was partially offset by an increase in deferred income tax benefit of US$17.0 million, or 35.7%, from US$47.7 million to US$64.7 million primarily as a result of a tax benefit of US$77.2 million related to our recognition of a substantial increase in the fair value of our contingent consideration obligation to Petrobras, the effect of which was partly offset by the utilization of Brazilian tax losses and temporary differences arising from foreign exchange movements in the U.S. dollar and Brazilian real exchange rate.

Liquidity and capital resources

Overview

We primarily rely on cash from operations and existing cash on hand in order to fund our operations and capital expenditures. Our ability to fund our business using cash from operations has been and will continue to be influenced by a variety of factors, including those described under "—Key factors affecting our results."

We have historically grown our business by acquiring assets, and we continue to regularly evaluate opportunities to acquire additional assets and companies. See "Business—Our strategy—We intend to grow production volumes through acquisitions, targeting opportunities in North America and Brazil, that leverage our technical expertise and teams in these regions" for more information about our acquisition strategy. We have historically relied on free cash on hand and prudent leverage of the balance sheet through debt facilities as well as equity issuances in order to fund significant acquisitions.

We intend to apply our capital to:

- safe and reliable operating costs;
- sustaining capital expenditure;
- debt servicing; and
- growth investment, balanced with returns to shareholders.

We believe that we have sufficient sources of funds to meet our capital requirements over the next 12 months.

As of December 31, 2023, we had total available liquidity of US$170.4 million, all of which was cash and cash equivalents. As of December 31, 2023, we had outstanding borrowings of US$274.1 million, all of which was first-lien senior secured debt. As of December 31, 2023, we had US$66.0 million undrawn under our RBL facility, all of which was committed but unavailable pending the addition of our interest in the Who Dat assets to the RBL facility borrowing base assets.

For more information about our material financing arrangements, see "Description of other financing arrangements."

Cash flows

Set out below is a summary of our cash flows for the periods indicated.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Cash flows from operating activities					
Receipts from customers	137.0	362.9	552.9	276.7	443.3
Payments to suppliers and employees	(56.5)	(116.5)	(135.2)	(66.8)	(106.2)
Payments for cash flow hedges	–	(20.8)	(13.4)	(12.7)	(2.7)
Borrowing and other costs of finance paid	(13.2)	(18.9)	(19.8)	(9.3)	(9.2)
Income taxes paid	(10.8)	(39.4)	(78.8)	(20.9)	(19.5)
Other operating activities(1)	(26.7)	(13.1)	0.2	0.1	(2.3)
Net cash from operating activities	**29.8**	**154.2**	**305.9**	**167.1**	**303.4**
Cash flows from investing activities					
Acquisition of oil and gas assets	(150.0)	(43.6)	(84.5)	–	(636.8)
Acquisition of exploration and evaluation assets	–	–	–	–	(83.0)
Payments for:					
Oil and gas assets	(16.0)	(59.6)	(222.5)	(137.1)	(4.2)
Exploration and evaluation expenditure capitalized	(1.9)	–	(43.1)	(0.5)	(3.3)
Other investing activities(2)	(1.3)	(9.8)	(6.1)	(4.8)	(0.8)
Net cash used in investing activities	**(169.2)**	**(113.0)**	**(356.2)**	**(142.4)**	**(728.1)**
Cash flows from financing activities					
Principal elements of lease payments	(23.4)	(44.6)	(34.1)	(19.7)	(19.2)
Proceeds from borrowings	–	30.0	–	–	274.0
Proceeds from issue of ordinary shares	–	2.4	–	–	312.3
Other financing activities(3)	–	(3.3)	(0.1)	–	(47.3)
Net cash (used in)/from financing activities	**(23.4)**	**(15.5)**	**(34.2)**	**(19.7)**	**519.8**
Net (decrease)/increase in cash and cash equivalents	(162.8)	25.7	(84.5)	5.0	95.1
Cash and cash equivalents at the beginning of the period	296.4	133.3	157.7	157.7	74.8
Effect of exchange rate changes on the cash and cash equivalents held in foreign currencies	(0.4)	(1.3)	1.6	0.5	0.5
Cash and cash equivalents at the end of the period	**133.2**	**157.7**	**74.8**	**163.2**	**170.4**

Notes:

(1) Includes cash flows from net refunds for Peruvian Vat, payments for exploration and evaluation expenditure expensed, payments for Baúna transition expenditure, payments for legal settlement and interest received.

(2) Includes cash flows from interest received on deposit, purchase of plant and equipment and computer software, borrowing costs paid for qualifying assets, payment for security deposits and proceeds from disposal of non-current assets.

(3) Includes cash flows from payment of equity raising costs, repayment of borrowings and debt facility costs.

Cash flows from operating activities

Net cash inflows from operating activities increased US$136.3 million, or 81.6%, in TY23 from cash inflows of US$167.1 million in HY23 to cash inflows of US$303.4 million for TY23. This increase was primarily due to receipts from customers increasing US$166.6 million, or 60.2%, from US$276.7 million to US$443.3 million, reflecting our higher sales volumes in TY23. This increase was partially offset by payments to suppliers and employees increasing US$39.4 million, or 59.0%, from US$66.8 million to US$106.2 million, primarily due to increased royalties and other government take as a result of our higher production volumes in TY23.

Net cash inflows from operating activities increased US$151.7 million, or 98.4%, in FY23 from cash inflows of US$154.2 million for FY22 to cash inflows of US$305.9 million for FY23. This increase was primarily due to receipts from customers increasing US$190.0 million, or 52.4%, from US$362.9 million to US$552.9 million, reflecting our higher oil sales volumes in FY23. This increase was partially offset by an increase in income taxes paid of US$39.4 million, or 100.0%, from US$39.4 million to US$78.8 million, reflecting the profit we earned during FY23 compared to the loss in FY22.

Net cash inflows from operating activities increased US$124.4 million, or 417.4%, in FY22 from cash inflows of US$29.8 million for FY21 to cash inflows of US$154.2 million for FY22. This increase was primarily due to receipts from customers increasing US$225.9 million, or 164.9%, from US$137.0 million to US$362.9 million, reflecting our higher oil sales volumes as a result of us operating Baúna for a full year and our higher weighted average realized oil price (net of selling expenses) in FY22. This increase was partially offset by an increase in payments to suppliers and employees, including production costs and royalties, of US$60.0 million, or 106.2%, from US$56.5 million to US$116.5 million, reflecting our higher oil sales volumes in FY22. This increase in net cash inflows was also partially offset by an increase in income taxes paid of US$28.6 million, or 264.8%, from US$10.8 million to US$39.4 million, primarily due to our increased profits in Brazil.

Cash flows from investing activities

Net cash outflows from investing activities increased US$585.7 million in TY23 from US$142.4 million for HY23 to US$728.1 million for TY23. This increase was primarily due to our acquisition of the Who Dat assets in TY23, which led to cash outflows of US$636.8 million and US$83.0 million for the acquisition of oil and gas assets and the acquisition of exploration and evaluation assets, respectively. This increase was partially offset by payments for oil and gas assets decreasing US$132.9 million, or 96.9%, from US$137.1 million to US$4.2 million, primarily due to the Baúna workover program and Patola development that we undertook during HY23 and which were completed prior to TY23.

Net cash outflows from investing activities increased US$243.2 million, or 215.2%, in FY23 from US$113.0 million for FY22 to US$356.2 million for FY23. This increase was primarily due to an increase in payments for oil and gas assets of US$162.9 million, or 273.3%, from US$59.6 million to US$222.5 million in connection with capital expenditure for the Baúna workover program, Patola development and ongoing field maintenance. This increase also reflected an increase in cash outflows for the acquisition of oil and gas assets of US$40.9 million, or 93.8%, from US$43.6 million to US$84.5 million, primarily related to the payment of deferred contingent consideration to Petrobras for the Baúna acquisition. Payments for capitalized exploration and evaluation expenditure also increased from US$0 to US$43.1 million primarily due to the two well control drilling campaign on the Neon discovery block we conducted during FY23.

Net cash outflows from investing activities decreased US$56.2 million, or 33.2%, in FY22 from US$169.2 million for FY21 to US$113.0 million for FY22. This decrease in cash outflows was primarily due to a decrease in cash outflows for the acquisition of oil and gas assets of US$106.4 million, or 70.9%, from US$150.0 million to US$43.6 million. The cash outflow for FY21 related to the Baúna acquisition completion payment, whereas the cash outflow for FY22 related to deferred firm consideration paid to Petrobras for the Baúna acquisition. This decrease in cash outflows was partially offset by an increase in payments for oil and gas assets of US$43.6 million, or 272.5%, from US$16.0 million to US$59.6 million primarily due to capital expenditure relating to the Baúna workover program and ongoing field maintenance.

Cash flows from financing activities

We had net cash inflows from financing activities of US$519.8 million in TY23 as compared to net cash outflows from financing activities of US$19.7 million in HY23. The main cash inflows in TY23 were from proceeds from the issue of ordinary shares and proceeds from borrowings of A$480 million and US$274.0 million, respectively, both of which were used to fund our acquisition of asset interests from LLOG. These cash inflows were partially offset by equity raising costs and debt facility costs of US$8.8 million and US$8.6 million, respectively.

Net cash outflows from financing activities increased US$18.7 million, or 120.6%, in FY23 from US$15.5 million for FY22 to US$34.2 million for FY23. This increase was primarily due to the non-recurrence of a debt facility drawdown of US$30.0 million that occurred during FY22. The increase was partially offset by cash outflows for principal elements of lease payments decreasing US$10.5 million, or 23.5%, from US$44.6 million to US$34.1 million primarily due to the temporary shutdown of the floating production, storage and offloading facility.

Net cash outflows from financing activities decreased US$7.9 million, or 33.8%, in FY22 from US$23.4 million for FY21 to US$15.5 million for FY22. This decrease was primarily due to a US$30.0 million debt facility drawdown during FY22. The decrease in net cash outflows was partially offset by an increase in cash outflows for principal elements of lease payments of US$21.2 million, or 90.6%, from US$23.4 million to US$44.6 million due to us leasing the floating production, storage and offloading facility for the full fiscal year in FY22.

Dividends

We have not declared or paid any dividends in the three and a half years ended December 31, 2023.

Financing arrangements

As of December 31, 2023, we had total available liquidity of US$170.4 million, all of which was cash and cash equivalents.

Existing debt facilities

As of December 31, 2023, the only material debt facility we had outstanding was the revolving RBL facility, which we entered into on November 16, 2023. We made an initial drawdown of this facility on December 18, 2023 in connection with the acquisition of interests in the Who Dat assets. To the extent we have available capacity under the RBL facility, we may drawdown this facility for general corporate purposes (other than for the purpose of paying a dividend). For more information about this facility, see "Description of other financing arrangements."

As of December 31, 2023, this facility had a facility limit of US$340 million, of which we had drawn US$274.0 million. The remaining US$66.0 million under this facility was committed but unavailable due to the current level of reserves in our borrowing base assets. We are currently in the process of incorporating our interest in the Who Dat oil and gas fields into our borrowing base assets, and we expect this process to complete by June 30, 2024. While the process is ongoing and the related calculation remains subject to further confirmation, we expect the committed but unavailable amount under our RBL facility to become available after this process is completed. After March 2026, this facility limit will be reduced on a straight-line basis semi-annually to September 30, 2028. This facility will mature on the earlier of (i) September 30, 2028 and (ii) the date on which the 2P reserves of the borrowing base assets will be equal to or less than 25% of our 2P reserves of the borrowing base assets as of December 18, 2023.

The carrying value of these borrowings, which represents the drawn amount less US$9.6 million of unamortized transaction costs, was US$264.4 million. Our RBL facility bears floating rates of interest calculated by reference to a margin over the Secured Overnight Financing Rate ("SOFR") and a credit adjustment spread. The weighted average interest rate of this facility during TY23 was approximately 9.64% per annum. We are required to enter into hedging arrangements under the RBL facility to mitigate our exposure to movements in oil prices by reference to a minimum and maximum proportion of our forecast production over the next two years. See "—Key factors affecting our results—Oil and gas prices" for more information about our hedging requirements.

We are subject to a number of financial covenants under the RBL facility. For more information about these financial covenants, see "Description of other financing arrangements."

Prior debt facilities

We established a reserve-based, non-recourse, syndicated loan facility in November 2021. In April 2022, we established an additional accordion facility under this loan facility. These facilities were secured over the shares in and assets of the entity that holds our interest in the Baúna concession.

The two facilities combined had a facility limit of US$210.0 million, of which we had drawn down US$30.0 million as of June 30, 2023 and June 30, 2022. The carrying value of these borrowings, which represents the drawn amounts less US$1.9 million and US$2.9 million of unamortized transaction costs, respectively, were US$28.1 million and US$27.1 million as of June 30, 2023 and 2022, respectively. Our borrowings under these facilities bore floating rates of interest originally calculated by reference to a margin over LIBOR before being amended for SOFR in 2022. The weighted average interest rate of these facilities during FY23 and FY22 was 8.22% per annum and 5.95% per annum, respectively. We were required to enter into oil hedging in accordance with minimum and maximum hedge ratios under these facilities. These facilities also included a number of financial covenants, and we complied with all of these while these facilities were on foot.

During TY23, we repaid US$29.9 million of the US$30.0 million we had drawn down under this facility and canceled all other commitments under this facility. As of December 31, 2023, we had US$0.1 million outstanding under this facility. Since December 31, 2023, we have repaid and canceled this remaining balance.

Capital expenditure

We operate in a capital-intensive industry and invest substantial amounts of capital to maintain our operations, develop our growth projects and conduct exploration and evaluation activities. We undertake a phased project maturation process in an effort to de-risk our projects prior to spending material capital. As such, while the majority of capital expenditure for our projects will follow a final investment decision to develop the project, we will also spend significant amounts of time and capital studying the feasibility of these projects in order to determine whether to develop them.

The following table shows our total capital expenditure for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
			(US$ million)		
Oil and gas assets[(1)]	17.4	92.0	190.9	138.6	3.4
Exploration and evaluation	1.9	1.4	44.8	0.5	6.6
Other plant and equipment[(2)]	6.0	5.0	2.7	2.4	0.7
Total	**25.3**	**98.4**	**238.4**	**141.5**	**10.7[(3)]**

Notes:

(1) Excludes Baúna acquisition costs, capitalized borrowing costs associated with the Patola development and leased right-of-use asset additions.

(2) Excludes leased right-of-use asset additions.

(3) Excludes the acquisition of asset interests from LLOG.

During FY23, we completed the Baúna workover program, developed the Patola field as a subsea tieback and completed a two well control drilling campaign as part of the Neon discovery. Our capital expenditure related to exploration and evaluation included the expenditure related to our Neon discovery. We funded these projects with cash flows from operations and existing cash on hand, with no further drawdowns from our debt facilities. The Baúna workover program and Patola development involved significant levels of capital expenditure over the three years ended June 30, 2023, and we expect to transition to a less capital intensive operating phase at Baúna going forward. See "Business—Brazil—Producing assets—Baúna—Operational overview" for more information about these two programs. We expect our future capital expenditures to be mainly associated with the Who Dat assets.

We expect to spend US$137 million to US$164 million in capital expenditure during 2024, comprising US$87 million to US$102 million related to exploration work at the Who Dat assets, US$13 million to US$14 million related to exploration work at the Neon discovery and US$37 million to US$48 million related to sustaining capital expenditure.

Off-Balance Sheet Arrangements

Other than as disclosed below under "—Contingent liabilities" and "—Commitments for expenditure," we have no other significant off-balance sheet liabilities.

Contingent liabilities

Letter of credit

We provided ANP a letter of credit to guarantee our performance of a minimum work program in relation to exploration in an exploration tenement in the Santos Basin. We fully funded this letter of credit through the payment of a security deposit, which will be released once the work program is met. There is a risk that we will lose this security deposit should we not satisfy our work program commitments. As of December 31, 2023, the value of the security deposit was US$2.1 million.

Bank guarantees

We have provided bank guarantees in respect of rental agreements for our office premises. These guarantees may give rise to liabilities if we do not meet our obligations under these guarantees. We have fully funded these bank guarantees through the payment of a security deposit. As of December 31, 2023, the value of the security deposits were US$0.2 million.

Cash deposits

We have guaranteed payment obligations to various accommodation providers in Brazil and Peru. We have deposited cash to be held as bonds for our compliance with such obligations. As of December 31, 2023, the value of these cash deposits were US$0.4 million.

Notice of infraction

We have received a notice of infraction from the Santos Municipality for Brazilian real $9.1 million (equivalent to approximately US$1.8 million as of December 31, 2023), inclusive of fines and interest, related to a municipal tax levied on the provision of services on activities carried out by service providers at the *Cidade de Itajaí* floating production, storage and offloading facility. We have rejected the liability and are defending the action.

Block acquisition

As part of our acquisition of Pacific Exploration and Production Corp.'s equity interest in various Santos Basin exploration tenements during the year ended June 30, 2017, we agreed to pay Pacific Exploration and Production Corp. deferred contingent consideration of US$5.0 million payable when 1.0 MMboe is produced from these tenements. We have not provided for this deferred contingent obligation as of December 31, 2023 as it is dependent on uncertain future events.

Brazilian local content

Our concession contracts for a number of Santos Basin exploration tenements require us to acquire a minimum proportion of goods and services from Brazilian suppliers. The minimum requirement under these concession contracts during the exploration and appraisal phase for these tenements is up to 55%. If we fail to comply with this minimum requirement, we may be subject to a fine by the ANP.

Other matters

We are subject to legal claims and exposures which arise during our ordinary course of business. As of December 31, 2023, we do not expect any material loss to result from such claims. For more information, see "Business—Legal proceedings."

Commitments for expenditure

We have entered into contracts for capital and service expenditure in relation to assets and these payment obligations are not provided for in our consolidated financial statements. We also have service commitments which predominately relate to the operating and maintenance contract with OOG-TKP. This services contract has a daily rate for operations payable under the contract. We also have guaranteed commitments for exploration expenditure arising from obligations to governments to perform minimum exploration and evaluation work and expend minimum amounts of money pursuant to the award of an exploration tenement. None of these commitments are provided for in our consolidated financial statements.

The table below sets out these commitments as of December 31, 2023.

	As of December 31, 2023		
	Total	**Less than 1 year**	**Later than 1 year but not later than 5 years**
		(US$ million)	
Capital and service expenditure commitments	**16.1**	16.1	–
Service commitments	**32.1**	16.8	15.3
Exploration expenditure commitments	**27.5**	5.0	22.5
Total	**75.7**	**37.9**	**37.8**

Since December 31, 2023, the respective joint venture partners have approved the drilling of an appraisal well and an exploration well in Who Dat East and Who Dat South, respectively, and we expect the total cost of the two wells to us to be between US$67 million and US$77 million. We expect the capital expenditure for these two wells to be incurred during the year ending December 31, 2024.

These figures do not include any commitments in relation to certain exploration tenements related to the Neon and Goia discoveries. In January 2019, we submitted both a Final Discovery Evaluation Report and Declaration of Commerciality for these discoveries in accordance with Brazilian regulatory requirements. While this transitioned the tenements from the exploration phase to the development phase from a Brazilian regulatory perspective, it does not mean that we have reached, nor are we compelled to reach, a final investment decision with respect to these discoveries. As such, we have not recognized any commitments for expenditure with respect to these tenements.

We estimated our future exploration expenditure commitments based on estimated well and seismic costs, which will change as actual drilling locations and seismic surveys are completed and are calculated in current dollars on an undiscounted basis. Our exploration and evaluation obligations may also vary significantly as a result of renegotiations with the relevant parties. In addition, we may also reduce our exploration expenditure commitments by entering into farm-out agreements or by relinquishing our exploration tenements.

Quantitative and qualitative disclosure about market risk

Our activities expose us to a variety of financial risks including market risk (including foreign exchange risk and interest rate risk), commodity price risk, credit risk and liquidity risk. Our overall financial risk management program focuses on the unpredictability of financial markets and seeks to minimize potential adverse effects on our financial performance. We use different methods to measure the different types of financial risk to which we are exposed. These methods include a sensitivity analysis in the case of foreign exchange, interest rate and commodity prices.

Our Board of Directors, through the audit, risk and governance committee, manages our overall financial risk management strategy. Our strategy is focused on ensuring that we are able to finance our business plans while minimizing potential adverse effects on our financial performance. Our Board of Directors provide written principles for overall financial risk management, as well as written policies covering specific areas, such as mitigating foreign exchange, interest rate, commodity price and credit risks, use of derivative financial instruments and investment of excess cash.

Our finance function carries out financial risk management in accordance with policies approved by the Board of Directors. Our finance function identifies, evaluates and if necessary, hedges financial risks in close co-operation with our chief executive officer. We regularly review our risk management policies and systems to reflect changes in market conditions and our activities.

Foreign exchange risk

Our reporting currency is U.S. dollars. Our revenue, significant operating expenditure including the floating production, storage and offloading facility charter and a large component of capital obligations are predominantly denominated in U.S. dollars. Our foreign exchange risk exposures primarily relate to administrative and business development expenditures which are incurred in Australian dollars and a portion of our operating and capital expenditures related to our Baúna production assets and the payment of Brazilian taxes which are incurred in Brazilian real. We translate these items to their U.S. dollar equivalents at period end and recognize the associated gain or loss in our income statement.

We manage our foreign exchange risk by monitoring forecast cash flows in currencies other than U.S. dollars and ensuring that we maintain adequate Brazilian real and Australian dollar cash balances to meet our requirements. We purchase foreign currencies on the spot market where necessary. Where we purchase foreign currency in advance of requirements, these purchased amounts do not usually exceed the foreign currency amounts we estimate we will need over the next three months. The main exception to this is the Brazilian real we purchase to settle our corporate income tax true up liability, which we accumulate over a 12 month period. We regularly review the appropriateness of our Australian dollar and Brazilian real cash holdings against our expenditure commitments.

We periodically conduct sensitivity analyses to evaluate the potential impact of unfavorable exchange rates on our future financial position. We use the results to determine the most appropriate risk mitigation tool. We will hedge our foreign currency exposures when we deem it to be the most appropriate risk mitigation tool. As of December 31, 2023, we had no material transaction exposures as the majority of our financial assets and liabilities are denominated in U.S. dollars.

Interest rate risk

Interest rate risk is the risk that the fair value of future cash flows of our financial assets and financial liabilities will fluctuate because of changes in market interest rates. We manage this risk through the use of cash flow forecasts supplemented by sensitivity analyses. Our interest rate risk arises from long-term borrowings which accrue interest at floating interest rates and our cash and cash equivalents and security deposits which earn interest at floating interest rates. Our primary exposure is to U.S. dollar interest rates as our long-term borrowings and the majority of our cash and cash equivalents are denominated in U.S. dollars.

The following table sets out our exposure to interest rate risk for financial assets and financial liabilities as of December 31, 2023.

	As of December 31, 2023				
	Floating interest rate	Fixed interest rate	Non-interest bearing	Fair value	Carrying amount
			(US$ million)		
Financial assets					
Cash and cash equivalents	164.5	5.9	–	170.4	170.4
Receivables	–	–	56.4	56.4	56.4
Other financial assets	–	–	0.2	0.2	0.2
Total financial assets	164.5	5.9	56.6	227.0	227.0
Financial liabilities					
Trade and other payables	–	–	73.8	73.8	73.8
Borrowings	274.1	–	–	274.1	274.1
Other financial liabilities	–	222.5	–	222.5	222.5
Lease liabilities	–	–	224.4	224.4	224.4
Total financial liabilities	274.1	222.5	298.2	794.8	794.8

The following table sets out how sensitive our profit/(loss) before income tax and financial instruments would be to a 1% per annum increase or decrease in interest rates as of December 31, 2023. This sensitivity analysis is not fully representative of our inherent interest rate risk, as the financial period end exposure does not necessarily reflect our exposure during the course of a financial period. This is particularly the case here as we only drew down on the RBL facility on December 18, 2023. This sensitivity analysis should also not be used to forecast the future effect of movements in interest rates on future cash flows.

	As of December 31, 2023
Change in profit/(loss) before income tax	
Increase of interest rate by 1% per annum	(1.0)
Decrease of interest rate by 1% per annum	1.0
Change in financial instruments	
Increase of interest rate by 1% per annum	(1.0)
Decrease of interest rate by 1% per annum	1.0

As of December 31, 2023, we had no interest rate hedging in place.

Commodity price risk

We are exposed to commodity price fluctuations due to our production and sale of oil and gas. To mitigate commodity price risk, we have entered into Brent crude oil price hedges utilizing a combination of puts and collar structures consisting of bought put and sold call options. During TY23 and FY23, approximately 26% and 37% of reported production volume was hedged, respectively. As of December 31, 2023, we held hedging instruments with a net asset carrying value of US$0.2 million.

As of December 31, 2023, a 10% increase or decrease in Brent crude oil prices would have had no material impact on the carrying value of our hedging instruments.

As part of our acquisition of Baúna, we agreed to pay Petrobras contingent consideration of up to US$285 million plus interest of 2% per annum accruing from January 1, 2019. We account for the fair value of this contingent consideration arrangement as an embedded derivative and estimate it by calculating the present value of the future expected cash outflows. We make these estimates based on our internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts. The following table details our sensitivity to a 10% increase or decrease in our internal assessment of future oil prices on the contingent consideration payable to Petrobras. As of December 31, 2023, as the US$70 per barrel threshold was triggered over calendar years 2022 and 2026, the maximum contingent consideration payable has already been recognized. As such, a 10% increase in oil price would have no impact on the fair value of the contingent consideration payable to Petrobras.

	As of December 31, 2023
Change in profit/(loss) before income tax	
Increase in oil price of 10%	–
Decrease in oil price of 10%	21.9
Change in financial liabilities	
Increase in oil price of 10%	–
Decrease in oil price of 10%	(21.9)

Credit risk

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to us. This risk arises from cash and cash equivalents and security deposits held with banks, financial institutions and joint operators, as well as credit exposures to customers, including outstanding receivables and refundable tax credits. To minimize our credit risk, we have adopted a policy of only dealing with recognized and creditworthy third parties and we monitor our credit exposure and the external credit ratings of our counterparties on a periodic basis. See Note 21(c) to our audited consolidated financial statements for TY23 for more information on how external credit ratings of banks and financial institutions impact our choice of cash and cash equivalents and security deposit counterparties. Where commercially practical, we seek to limit the amount of credit exposure to any one bank or financial institution. We also minimize our exposure to bad debts by monitoring our receivables balances on an ongoing basis. We do not hold collateral nor do we securitize our receivables.

In TY23 and FY23, all of our revenues from Brazil and the USA were earned from sales to a single customer. We expect the substantial majority of our revenues from Brazil and the USA to be earned from sales to a small number of customers in future periods.

We have two types of financial assets that are subject to AASB 9's 'expected credit loss' model: receivables and security deposits. Under this model, we will reduce the carrying amount of the relevant financial asset through the use of a loss allowance account and recognize this loss on our income statement. We measure the expected credit loss based on available external credit ratings, historical loss rates and the days past due. While our cash and cash equivalents are also subject to these impairment requirements, we did not consider the identified impairment loss to be significant given the counterparties and/or the short maturity.

We consider our receivables relating to Brazil and Australia to have low credit risk on the basis that there is a very low risk of default and the debtor has a strong capacity to meet its obligations in the short-term. As such, we use a 12-month expected credit loss model measure for any impairment test of receivables. As of December 31, 2023, the loss allowance for receivables recognized during TY23 for receivables was US$0.

Liquidity risk

We manage liquidity risk by ensuring that there are sufficient funds available to meet financial obligations on a day-to-day basis and to meet unexpected liquidity needs in the normal course of business. We place emphasis on ensuring there is sufficient funding in place to meet the ongoing operational requirements of our production activities, exploration, evaluation and development expenditure and other corporate initiatives. We use the following mechanisms to manage liquidity risk:

- preparing and maintaining rolling forecast cash flows in relation to operational, investing and financing activities;
- comparing the maturity profile of financial liabilities with the realization profile of financial assets;
- managing credit risk related to financial assets;
- when necessary, utilizing short-term and long-term loan facilities;
- investing surplus cash only in credit quality banks and financial institutions; and
- maintaining a reputable credit profile.

The following table analyzes the contractual maturities of our financial liabilities as of December 31, 2023. The amounts disclosed in the table are the contractual undiscounted cash flows comprising principal repayments.

	As of December 31, 2023					
	Less than 6 months	6 to 12 months	1 to 3 years	3 to 5 years	Over 5 years	Total
	(US$ million)					
Financial liabilities						
Non-derivative financial liabilities						
Trade and other payables	67.9	–	5.9	–	–	73.8
Borrowings	0.1	–	91.3	182.7	–	274.1
Lease liabilities	30.0	30.3	119.8	73.2	–	253.3
Derivative financial liabilities						
Contingent consideration – embedded derivative	86.0	–	87.6	58.6	–	232.2
Total financial liabilities	184.0	30.3	304.6	314.5	–	833.4

Critical accounting policies

Critical accounting policies are policies that require us to make significant estimates, assumptions and/or judgments that may significantly affect the reported amounts of assets, liabilities, revenues or expenses. We make these estimates, assumptions and/or judgments based on historical knowledge and best available current information and assume a reasonable expectation of future events based on current trends and economic data obtained both externally and internally. In preparing our consolidated financial statements, we have made a number of judgments and have applied estimates and assumptions to future events.

The following disclosure discusses the estimates, assumptions and/or judgments that we are required to make in the application of those critical accounting policies. For more information about our critical accounting policies, you should refer to the discussion in the notes to our audited consolidated financial statements for TY23 and the discussion of key audit matters referred to in the audit report attached thereto, included elsewhere in this offering memorandum.

Impairment of oil and gas assets

We assess whether our oil and gas assets are impaired on at least a semi-annual basis. If any indication of impairment exists, we will recognize an impairment loss if the carrying amount of an asset or cash-generating unit exceeds its estimated recoverable amount. The recoverable amount of an asset is the higher of the asset's fair value less costs of disposal and value in use.

For our oil and gas properties, the expected cash flow we use in calculating their fair value less costs of disposal is based on our reserves estimate, future production profiles, forecasted commodity prices and estimated costs, all of which are uncertain. The estimates we make with respect to these factors are likely to change from period to period, and we may recognize significant levels of impairment on our income statement as a result of such changes.

Capitalized exploration and evaluation expenditure

We capitalize exploration and evaluation expenditure on the basis that exploration and evaluation operations in the areas of interest have not, at the end of the reporting period, reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and where active and significant operations in, or in relation to, the areas of interest are continuing.

The future recoverability of our capitalized exploration and evaluation expenditure is dependent on a number of factors that require our judgment, including whether we decide to exploit the related exploration tenement or, if not, whether we successfully recover the related exploration and evaluation asset through sale. Factors that could affect the future recoverability of this expenditure include:

- the level of economically recoverable reserves;
- future technological changes which could impact the cost of development;
- future legal changes, including changes to our environmental and restoration obligations; and
- changes to commodity prices.

All of these factors require us to make estimates, judgments and/or assumptions at the end of each reporting period. To the extent we determine that capitalized exploration and evaluation expenditure will not be recoverable in the future, the relevant amounts will be impaired in our income statement and our assets will be reduced.

Provision for restoration

We recognize a provision for restoration where there is a present obligation as a result of exploration, development or production activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation.

We have recognized a provision for our restoration obligations with respect to the Baúna oil field. The calculation methodology we employ in determining our restoration obligations is different from the methodology employed by the ANP. The value of the surety bond we have provided in connection with our existing decommissioning obligations was calculated using ANP's methodology. For more information about this surety bond, see Note 23(c) to our audited consolidated financial statements as of and for TY23. We have also recognized a provision for our restoration obligations with respect to the Who Dat oil and gas fields.

We include in our restoration provision the estimated costs of decommissioning and removing an asset and restoring the site. We base this estimate on judgments and assumptions regarding removal dates, technologies, industry practice and relevant legislation. In determining an appropriate level of provision, we consider the:

- expected future costs to be incurred;
- timing of these expected future costs;
- estimated future level of inflation; and
- appropriate discount rate.

The ultimate costs of restoration are uncertain and we may revise our cost estimates in subsequent years due to many factors including changes to the relevant legal and legislative requirements, the emergence of new restoration techniques and experience at other fields. Any change in our estimates could result in a significant change to the level of provisioning required, which would in turn impact future financial results.

Estimates of reserves quantities

Our estimated quantities of 2P hydrocarbon reserves are integral to the calculation of amortization expense and to the assessment of impairment or impairment reversals.

We estimate reserve quantities based on:

- our interpretation of geological and geophysical models;
- reservoir engineering and production engineering analyses and models; and
- assessments of the technical feasibility and commercial viability of producing the reserves.

Our reserves assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes. Our estimates of reserves may change from period to period as the economic assumptions used to estimate the reserves can change from period to period. They may also change as additional geological data is generated through the course of operations. Any such changes may impact depreciation, amortization, asset carrying values, restoration provisions and deferred tax balances. If we revise downwards our proved and probable reserves estimates, our earnings could be affected by a higher depreciation and/or amortization charge or the immediate write-down of the carrying value of assets.

Fair value measurement of financial instruments

We measure the fair value of financial assets and financial liabilities using valuation techniques including the discounted cash flow model when they cannot be measured based on quoted prices in active markets. Our calculation of the fair value of our contingent consideration arrangement (as described above) is based on our internal assessment of future oil prices, which considers industry consensus and observable prices, inflation and an appropriate risk-free rate. Any changes in our assumptions relating to these factors could affect the reported fair value of the financial instrument.

Income tax

We are subject to income taxes in Australia, Brazil, the USA and other jurisdictions where we have foreign operations. We undertake many transactions and calculations during the ordinary course of business for which the ultimate tax determination is uncertain. We estimate our tax liabilities based on our understanding of the relevant tax laws. Where the final tax outcome is different from the amounts that were initially recorded, such differences will impact our current and deferred tax balances.

We recognize deferred tax assets to the extent that we think it is probable that sufficient taxable amounts will be available against which deductible temporary tax differences or unused tax losses and tax offsets can be utilized. We offset deferred tax assets and liabilities when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. In calculating the amount of benefits brought to account or which may be realized in the future, we assume that there will be no adverse change in income tax legislation and that we will derive sufficient future assessable income to enable the benefit to be realized and comply with the conditions of deductibility imposed by law.

We make significant estimates related to expectations of future taxable income when assessing the future utilization of tax losses and temporary tax differences. Our estimates of future taxable income are based on forecast cash flows from operations and require us to assume the application of existing tax laws. To the extent that future utilization of these tax losses and temporary tax differences becomes probable, this could result in significant changes to the deferred tax assets recognized, which could in turn impact our future financial results.

Determining the lease term of contracts with renewal options

We determine the lease term as the non-cancellable term of the lease, together with any periods covered by an option to extend the lease if it is reasonably certain to be exercised, or any periods covered by an option to terminate the lease if it is reasonably certain not to be exercised. Our judgment with respect to the term of a lease will significantly influence the level of depreciation and amortization recognized in each reporting period with respect to that lease. See "—Key income statement line items—Cost of sales" and "—Key income statement line items—Finance costs—Finance charges on lease liabilities" for more information.

We have several lease contracts that include renewal options. We apply judgment in evaluating whether it is reasonably certain that we will or will not exercise the option to renew the lease. In making this judgment, we consider all relevant factors that create an economic incentive to exercise the renewal. After the commencement date of a lease, we will reassess the lease term if there is a significant event or change in circumstances that is within our control and affects our ability to exercise the option to renew or to terminate the lease. We included the renewal periods as part of the lease term for the floating production, storage and offloading facility right-of-use asset as there will be a significant negative effect on production if a replacement asset is not readily available.

New and amended reporting requirements

We have adopted the following amendments to accounting standards which became effective for TY23:

- AASB 2021-2 *Amendments to Australian Accounting Standards – Disclosure of Accounting Policies and Definition of Accounting Estimates;*

- AASB 2021-5 *Amendments to Australian Accounting Standards – Deferred Tax related to Assets and Liabilities arising from a Single Transaction*; and

- AASB 2023-2 *Amendments to Australian Accounting Standards – International Tax Reform – Pillar Two Model Rules.*

The adoption of these amended standards did not result in any changes to our accounting policies and has had no effect on either the amounts reported for the current or previous years.

We disclose the Australian Accounting Standards and Interpretations that have been issued or amended but are not yet effective as of December 31, 2023, in Note 1(a) ("New standards and interpretations not yet adopted") to our audited consolidated financial statements as of and for TY23.

Overview

We are an international offshore upstream oil and gas production and exploration company headquartered in Melbourne, Australia, with assets in Brazil and the United States of America. In Brazil, we own and operate the producing Baúna, Piracaba, and Patola fields, which we refer to as Baúna, and are party to concession agreements, in the Santos Basin. In the United States of America, we own non-operated interests in the producing Who Dat, Dome Patrol, and Abilene oil and gas assets, which we refer to as Who Dat, as well as interests in exploration licences, located in the US Gulf of Mexico. Our assets are diversified geographically with multiple producing wells in the Santos Basin and US Gulf of Mexico, which are prolific, globally recognized hydrocarbon basins providing us with the opportunity to increase our reserves and resources. At December 31, 2023, we had production from six oil fields and 19 producing wells, and eight pre-development and exploration blocks.

Our assets have demonstrated predictable reservoir characteristics and provide us with a high quality marketable product, as reflected in its sales prices. Our assets have relatively low production costs and low sustaining capital expenditure requirements compared to the overall oil and gas sector, resulting in a track record of our assets being highly cash generative with strong levels of free cash flow. We are also able to leverage our technical expertise and experience across our assets.

Our strategy is focused on delivering safe and reliable operations and value accretive growth through investment in our producing assets, development of in-field and near-field opportunities, and acquisitions intended to deliver us a material increase in the scale of our production. We have a track record of safe, efficient operation, and asset enhancement as an operator.

We believe, due to the quality of our existing assets, that our in-field and near-field drilling programs (which are in proximity to our existing producing assets) provide us with the potential to replace and increase our reserves and resources. We have increased production through the delivery of a workover program and development campaign in our Santos Basin assets, which were completed on time and on budget. See also "—Our production and exploration assets—Brazil—Producing assets—Baúna."

We have pursued value accretive growth through our acquisition of Who Dat in December 2023, which was funded through available cash, an equity raise, and drawings from our debt facility. We believe our financial policies are prudent relative to our peers, as evidenced by our low leverage. We are committed to delivering our growth strategy while maintaining financial discipline and a strong balance sheet.

We intend to continue to evaluate acquisition opportunities, focusing primarily on producing assets offshore the United States and Brazil that would increase our production, operating cashflow and profitability. Assets in these geographies would enable us to leverage our presence in Houston and Rio de Janeiro and our technical expertise in the region, as well as potentially providing opportunities to use existing infrastructure. However, we may also examine acquisition opportunities in other locations and at different stages of development.

In the 12 months to December 31, 2023, we generated revenues of US$680.0 million, underlying EBITDA of US$429.0 million, and cash flows from operating activities of US$442.2 million. On a pro-forma basis, assuming we owned the Who Dat assets since January 1, 2023, in the 12 months to December 31, 2023 we had revenues of US$827.4 million and underlying EBITDA of US$548.9 million. See "Unaudited pro forma combined financial information." At December 31, 2023, our PV-10 calculations on a 2P basis, according to AGR and NSAI for our Baúna and Who Dat assets totalled US$2,075 million[22] and we estimated our net oil and gas 2P reserves to be 77.5 MMboe.[23]

22 See "Cautionary note regarding PV-10 values" for further information on our PV-10 figures.

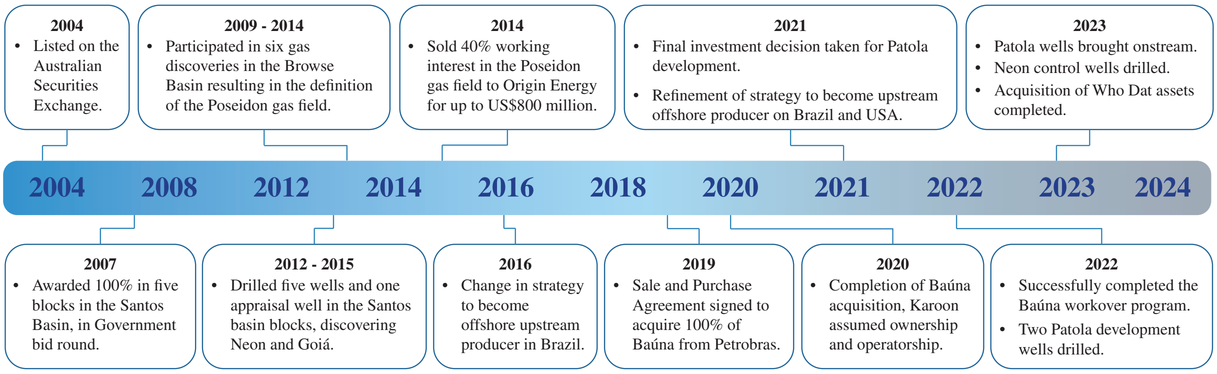
23 For more information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

We are headquartered in Melbourne, Australia, and we have regional offices in Houston, United States of America, and Rio de Janeiro, Brazil. We listed on the Australian Securities Exchange in 2004, and as of April 19, 2024, we had a market capitalization of A$1.7 billion (US$1.1 billion)[24], and employed more than 120 employees.

Company history

In our 20 years since listing on the Australian Securities Exchange, we have grown from our origins as an Australian focused oil and gas explorer to become a diversified oil and gas production and exploration company. We achieved this through the completion of two transformational acquisitions, namely the acquisition of Baúna in 2019 and its subsequent development and expansion, and the acquisition of the Who Dat assets in 2023. At December 31, 2023 we had assets in Brazil and in the United States of America with production from six oil fields and 19 producing wells, and eight pre-development and exploration blocks.

The following chart shows a number of our key corporate milestones.



We were incorporated as a public company under the name Karoon Gas Australia Limited in November 2003. In June 2004 we listed on the Australian Securities Exchange. Our core focus and strategy at that time was to identify, explore and develop prospective oil and gas acreage offshore Australia in the Browse and western Gippsland Basins.

In 2004, we acquired exploration permits in the Browse Basin in Western Australia. We subsequently farmed-out a 60% working interest in these blocks to ConocoPhillips. Under that arrangement, ConocoPhillips committed to fund a major multi-well work and seismic program. From 2009 to 2014, we participated in six gas discoveries from seven wells in the ConocoPhillips-operated Browse Basin exploration campaign, resulting in the definition of the multi-trillion cubic feet Poseidon gas field.

The Santos Basin, offshore Brazil, emerged in the mid-2000s as one of the most active and prospective hydrocarbon basins in the world. Noting this potential and the considerable offshore development being undertaken, in 2007, we participated in a government tender in Brazil, resulting in the award of 100% of the interest in five blocks in the Santos Basin. In 2012, we executed a farm-out agreement for a 35% interest in several of our wholly-owned Santos Basin exploration blocks with Pacific Exploration. We received US$40 million cash as consideration and Pacific Exploration agreed to carry out a multi-well drilling program of up to US$210 million. We subsequently drilled five exploration wells and one appraisal well in the Santos Basin blocks from 2012 to 2015 and made two discoveries, Echidna (Neon) and Kangaroo (Goiá). We assigned contingent resource oil estimates to Echidna (Neon) and Kangaroo (Goiá) in 2015.

In 2014, we sold our 40% working interest in our Browse Basin blocks for an US$600 million upfront cash payment and additional US$200 million in deferred contingent payments, payable by Origin Energy upon meeting certain milestones.

24 A$ translated to US$ at the Reserve Bank of Australia rate for April 19, 2024 of A$1.00 = US$0.6397.

In 2018, we changed our name from Karoon Gas Australia Ltd to Karoon Energy Ltd to reflect our ambitions to hold a diversified asset portfolio.

In 2019, we entered into a sale and purchase agreement with Petrobras to acquire a 100% operating interest in our core production license BM-S-40, located in the Santos Basin. The acquisition was for a headline purchase price of US$665 million, which we subsequently renegotiated during 2020 to include a US$380 million upfront payment, plus potential additional oil price-linked contingent payments of up to US$285 million. We funded this acquisition through a A$284 million equity raising and available cash, and completed the acquisition and assumed ownership and operatorship in November 2020. Baúna, our key Brazilian production asset, is located within the BM-S-40 production license.

In 2021, we took a final investment decision to develop the Patola field within BM-S-40. Patola is adjacent to the Baúna and Piracaba accumulations and is tied back to the existing Baúna floating production, storage and offloading vessel, *Cidade de Itajaí*. For additional information on the Patola development, see "—Our production and exploration assets—Brazil—Baúna."

In October 2021, we announced our refreshed strategy, reflecting our transition from an exploration company to a production and exploration company. At the same time, we strengthened our corporate governance structure and adopted our carbon management action plan. See "—Sustainability—Climate" for further details regarding our carbon management action plan.

Between May and September 2022, we undertook a workover program at Baúna consisting of the installation of new electric submersible pumps and gas lift equipment, leading to a significant production uplift from Baúna compared to when we took operatorship. See "—Our production and exploration assets—Brazil—Producing assets—Baúna—Operational overview."

We drilled two wells in the Patola reservoir in November 2022 and achieved first oil at Patola in March 2023. In January and March 2023, we drilled two control wells in our 100% owned Neon field. These wells captured additional data that resulted in an increase of our contingent and prospective resource estimates.

In December 2023, we completed the acquisition of a 30% non-operated interest in the producing Who Dat and Dome Patrol oil and gas fields in the US Gulf of Mexico. We also acquired an approximately 16% working interest in the producing Abilene field, and varying interests in adjacent exploration acreage. The Who Dat assets are a conventional deepwater oil and gas operation, located in approximately 800 meters of water, offshore Louisiana, which management believes is a high quality, low cost operation. The total consideration for this acquisition was US$720 million. As part of our acquisition, we also agreed to up to US$39.2 million in additional payments relating to the exploration of Who Dat East and Who Dat West. For additional information on our US Gulf of Mexico assets, see "—Our production and exploration assets—US Gulf of Mexico." We funded this acquisition through a A$480 million equity raising, a US$274 million drawdown of our reserve based lending facility (our "RBL facility") and existing cash.

Our strengths

We are a diversified independent oil and gas production and exploration company that is strategically focused on growth in the United States of America and Brazil. Our strategy, which we call "50 for 10", involves us growing our scale to achieve a minimum production of 50,000 boepd which we aim to sustain for no less than a 10 year period. We believe that our high quality assets, technical expertise, experienced board and management, and strong financial position with a robust balance sheet and strong free cash flow will support us in achieving our strategy, and our objective to grow our production and reserves.

We believe that our competitive strengths include:

We are an independent oil and gas company with high quality, conventional, low cost assets with low sustaining capital expenditure requirements and in-field and near-field production growth opportunities.

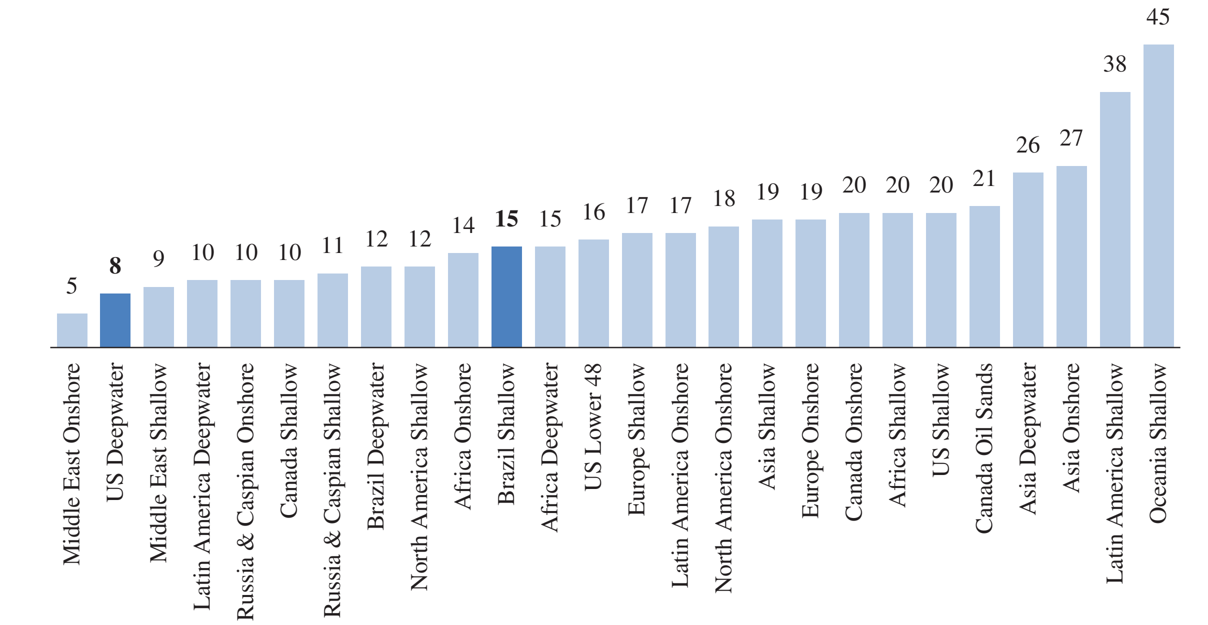
Our assets are conventional offshore assets, which management believes are high quality and low cost and which are in geographic locations that have extensive seismic information. Both the Baúna and Who Dat fields have a long production history and reservoir characteristics that are well understood by our technical teams, comprising our geoscientists and engineers. The predictability of our reservoirs helps us forecast production and cashflows.

Our assets are located in prolific hydrocarbon basins that have proven and well-understood subsurface characteristics. Our assets have in-field and near-field growth opportunities that provide potential to increase our production volumes and reserves, including through potential tie backs to our floating production and storage facilities. Employing tie backs would leverage our existing infrastructure, reducing our capital expenditure when developing assets, enabling us to increase production and reserves in a capital efficient manner and increase our free cash flow generation and profitability.

Our assets have relatively low production costs and low sustaining capital expenditure requirements compared to the overall oil and gas sector. During 2023, Baúna and Who Dat had average unit production costs of US$12.4/boe and US$7.9/boe, respectively. Given our relatively low capital expenditure requirements, on a portfolio basis, our cash breakeven price was US$22.40/boe during TY23.

Wood Mackenzie has prepared the below three-year aggregate unit production costs forecast (including transportation costs). Our unit production costs broadly align with the 'US Deepwater' and 'Brazil Shallow' categories, under which our operations are classified. According to Wood Mackenzie, these provide a proxy for the short-run marginal costs for onstream production across different resource themes and regions, and low operating expenditures reflect greater near-term resilience to commodity price declines for onstream assets.

Wood Mackenzie Unit Production Cost[25] by Resource Theme,
3-yr Aggregate Forecast per Barrel Expenditure 2024-2026



25 Source: Wood Mackenzie; Onstream, commercial liquids fields with remaining liquids resource > 25mmbbl. Unit production costs as defined only include fixed and variable operating expenses, transportation tariffs, and leasing costs. Royalties and G&A expenses are excluded from the unit cost. See "Cautionary note regarding industry and third-party data" and Annex B.

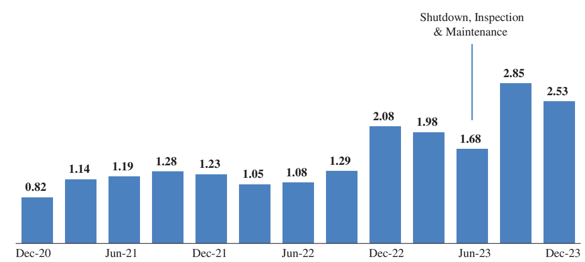
Wood Mackenzie, based on its analysis, considers that absolute demand growth coupled with a forecast supply gap provides a positive environment for long-term oil prices, which it forecasts to range from US$80/bbl to US$84/bbl (in real terms, 2023) between 2025 to 2035. If we are able to maintain our cash breakeven price and Wood Mackenzie's outlook proves accurate, it would allow us to generate strong cash margins and provide us with financial resilience to withstand material downturns in oil prices.

Our producing assets are strategically located in prolific hydrocarbon regions, and have a track record of predictable and efficient production.

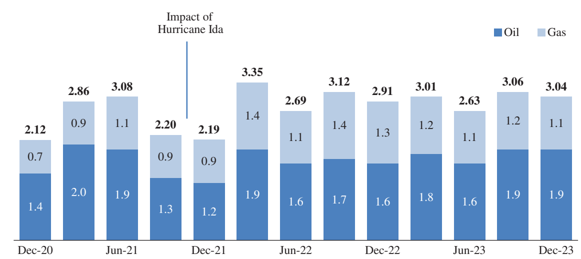
Our assets are located in the Santos basins and the US Gulf of Mexico, two regions that are recognized globally as prolific hydrocarbon basins. We believe that our strategic focus in these regions allows us to realize financial and operational synergies including: (i) the geological properties and reservoir characteristics of our assets are similar, allowing us to leverage our technical expertise and the experience of our geoscientists and engineers across our portfolio, (ii) integration of operating teams and centralization of logistics with proximity of teams located in similar time zones, (iii) synergies in managing supplier and customer relationships, delivering efficiencies and realizing economies of scale due to the increased size of our operations, and (iv) within each region, established infrastructure and pipelines which may reduce development costs and capital expenditure. We believe the strategic location and proximity of our assets contribute to our ability to generate strong free cash flows.

Our assets, which management believes are high quality, have reservoir characteristics that are well understood, and use conventional oil and gas extraction methods, which have historically resulted in predictable production.

Baúna – Quarterly Production History (MMbbl)



Who Dat – Quarterly Production History (MMboe)[26]

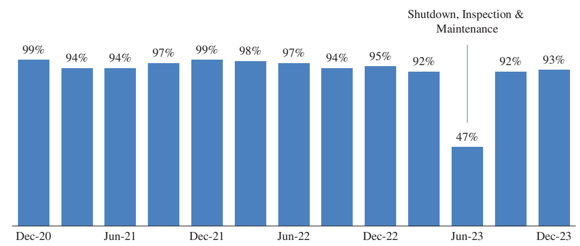


Our Baúna floating production, storage and offloading facility has achieved an average efficiency rate of 95%[27] over the period from November 7, 2020, when we commenced as operator of Baúna, to December 31, 2023. The Who Dat floating production and storage facility has achieved an average uptime rate of 94% since inception, being December 10, 2011 to March 31, 2024. During the quarter ended December 31, 2023, our joint venture partners undertook remediation works for corrosion under insulation on an oil treater degasser, which we use to remove gases from our crude oil, resulting in the lower facilities uptime of 91%.

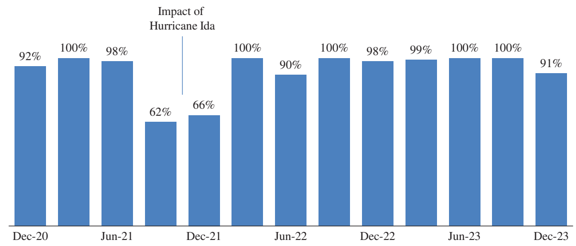
26 Gross production volumes. Source: Historical production data provided by LLOG. During 2021, Hurricane Ida caused 66 days of unplanned downtime as a result of pipeline damage in a downstream facility.

27 Excluding the March 2023 shutdown. See also "Business—Our production and exploration assets—Brazil—Producing assets—Baúna." Including the shutdown, the facility achieved an average efficiency of 91%.

Baúna – Quarterly FPSO Efficiency



Who Dat – Quarterly FPS Uptime

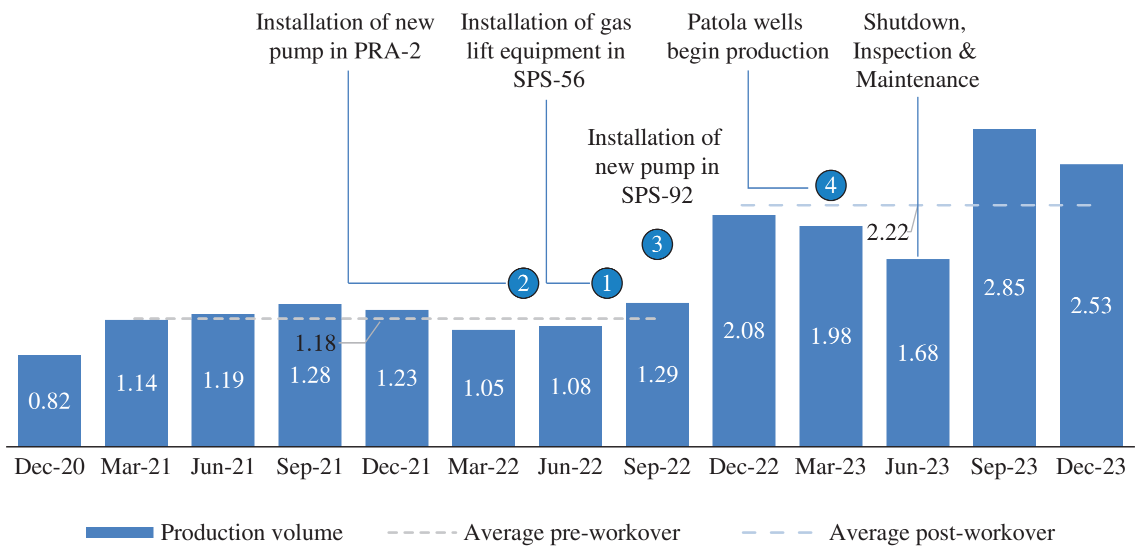


We have a strong track record as an operator, proven history of asset enhancement, and demonstrated technical expertise in the oil and gas industry.

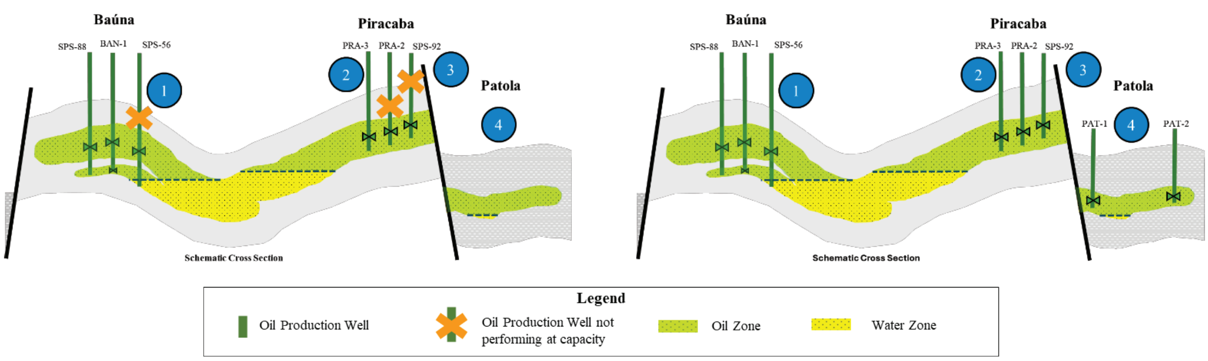
We have considerable experience and technical expertise, and have demonstrated our ability as an operator through our performance at Baúna. Since taking operatorship in November 2020, we have enhanced our asset base, having materially grown production through our workover programs and increased reserves through our in-field and near-field drilling programs. Excluding our six-week shutdown in the first half of 2023, we have also maintained high efficiency rates for the floating production, offload and storage facility at Baúna.

We undertook a workover program at Baúna from May 2022 to September 2022, replacing two electric submersible pumps and installing gas lift equipment, and delivered the development of Patola. This resulted in an increase in our average daily production from 14,600 bopd in March 2021, to a peak average daily production of 34,500 bopd in July 2023. Our workover program and the Patola development increased our 2P reserves by 28.9 MMbbls between December 31, 2020 and December 31, 2022 (not considering reductions through production from Baúna over that same period).

Baúna quarterly production volume (MMbbl)



Baúna assets prior to workover and Patola drilling | **Baúna assets after workover and Patola drilling**



We have strong relationships with our key business partners, and sell our production through marketing and offtake agreements to investment grade counterparties.

We aim to maintain strong and collaborative relationships with business partners, including our key stakeholders Shell, BP, LLOG and Westlawn.

Offtakers

Brazil – Production offtake arrangements with Shell

- Our production from Baúna is sold under a marketing and offtake agreement with SWST, a wholly-owned subsidiary of Royal Dutch Shell Plc.

- Under the terms of our marketing and offtake agreement, we receive payment from SWST. Shell currently has credit ratings of Aa2 (stable), A+ (stable), AA- (stable), from Moody's, S&P and Fitch, respectively, and is the 5th largest oil and gas company globally by market capitalization.

- We renewed our marketing and offtake agreement with SWST in November 2023, and SWST has been a lender under our RBL facility since October 2019.

US Gulf of Mexico – Production offtake arrangements with BP and Williams

- We sell our share of crude oil from Who Dat to BP Products North America Inc., a member of the BP Plc group under a month-to-month evergreen crude oil purchase agreement. We sell our share of natural gas from Who Dat on a six month seasonal contract basis to BP Energy Company, also a member of the BP Plc group under a gas purchase contract.

- BP Plc, which currently has credit ratings of A1 (stable), A- (positive), A+ (stable) from Moody's, S&P and Fitch, respectively. BP Plc is the 9th largest oil and gas company globally by market capitalization. BP Products North America Inc. and BP Energy Company have parent guarantees from BP Plc.

- We sell our share of natural gas liquids from Who Dat under a life-of-asset sales agreement at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation to Williams Field Services, a U.S. based natural gas infrastructure provider.

Operators & Partners

Brazil – Altera & Ocyan as owner and operator of the floating production, storage, and offloading facility

- Altera & Ocyan is a joint venture between Brazilian company, Ocyan, and Norwegian-headquartered, Altera Infrastructure, that owns and operates the floating production, storage and offloading facility at Baúna.
- We collaborate with Altera & Ocyan to manage required maintenance and enable continuous production.
- In December 2023, EIG, a global energy and infrastructure investor entered into definitive agreements to acquire Ocyan. EIG has significant investments in infrastructure supporting crude oil production.
- See "Risk factors—Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan."

US Gulf of Mexico – LLOG as operator and joint venture partner

- Our assets in the US Gulf of Mexico are operated by LLOG, a private independent US operator with extensive technical expertise and experience.
- At the time we acquired our interests in the Who Dat assets, LLOG had advised it had drilled 308 wells in the Gulf of Mexico since 2002, including 116 wells in deep water, and 14 wells at Who Dat.
- LLOG management has a history of performance, and we have a collaborative relationship.

US Gulf of Mexico – Westlawn as joint venture partner

- Westlawn Group is a private investment firm based in Houston, Texas, focused on long-term investment in the oil and gas industry.
- Westlawn is a joint venture partner in Who Dat. Westlawn's management team is well known to us and we have a collaborative relationship.

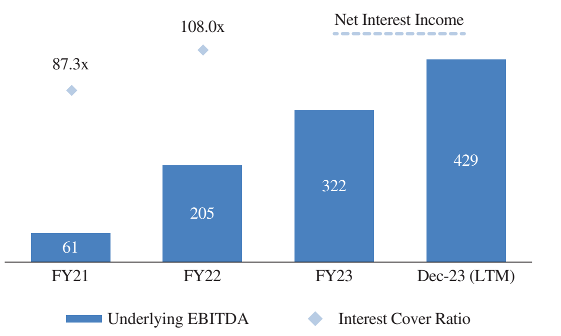
We believe our financial policies are prudent and we have delivered growth while maintaining our financial discipline and a strong balance sheet.

We have a track record of maintaining prudent financial policies and a strong balance sheet. We have maintained low leverage and financial discipline when funding acquisitions such as Baúna in 2019 and Who Dat in 2023. We believe our approach provides us with the flexibility to pursue our growth strategy and the ability to be opportunistic and respond promptly as opportunities emerge in our regions of focus. We consider our balance sheet to be a competitive advantage as it provides sellers with confidence in our ability to complete transactions.

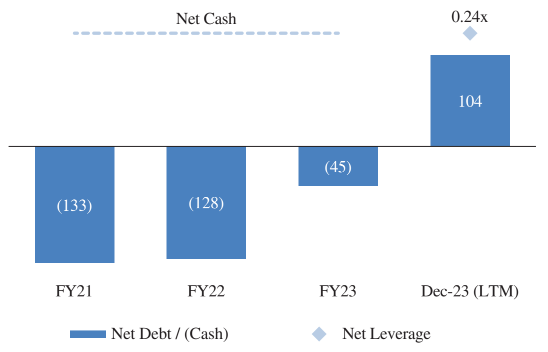
Our financial policies and financial discipline, and our low cash breakeven price of US$22.40 per boe during TY23 provide us with flexibility to remain unhedged (subject to our RBL facility obligations) and retain exposure to movements in oil and gas prices. We consider this important to maximize value for our stakeholders and generate strong free cash flow through the cycle.

We have a Board approved capital allocation framework that prioritizes safe and reliable operations and meeting capital commitments (sustaining capital expenditure, debt servicing, and other mandatory capital commitments). We expect that after meeting these commitments, we will have sufficient cash from our operations to fund growth initiatives and, where appropriate, make distributions to shareholders. In accordance with the capital allocation framework, our goal is to maintain a net leverage ratio of less than 1.0 times through the cycle.

Interest Cover Ratio – Underlying EBITDA/ Net Interest Expense



Net Leverage Ratio – Net Debt/ Underlying EBITDA

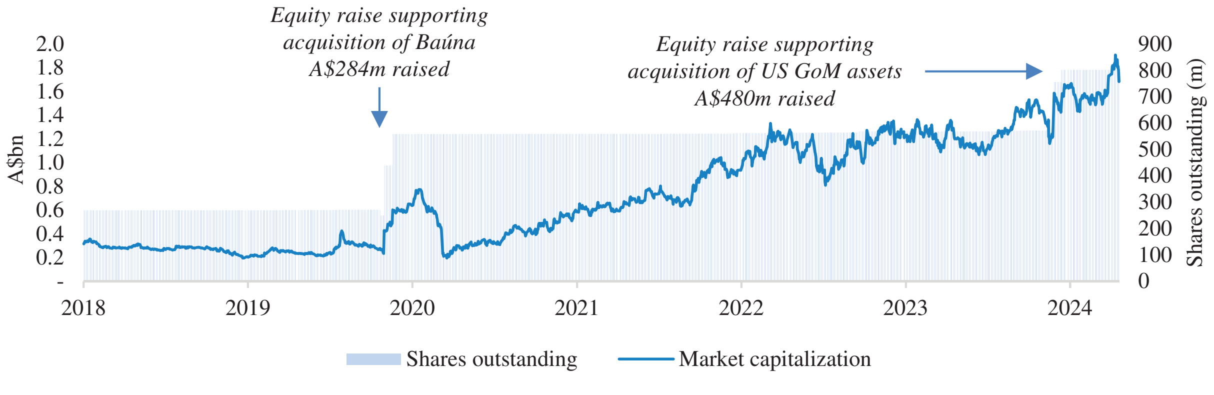


We have benefitted from strong support from capital providers. Our shareholders have supported our equity raisings to fund growth, and we have long term and supportive relationships that lend to us through our RBL facility.

Our capital providers have demonstrated their support and provided us with access to capital to fund growth, in both debt and equity markets, through the acquisition of Baúna, the refinancing of our RBL facility, and the acquisition of Who Dat.

Our shareholder register, at December 31, 2023 comprised approximately 74% institutional investors and 26% retail and other investors. The proportion of our register represented by institutional investors has increased from approximately 42% at the time that we completed the acquisition of Baúna, which we believe is the result of our transition from an explorer to a producing oil and gas company and demonstrates support from the equity market.

Equity Market Support



In respect of our debt relationships and support, in November 2021, we established the RBL facility, a reserve based syndicated loan facility, with total commitments of US$160 million. In April 2022, we increased the total facility limit to US$210 million, with the support of our existing banking relationships. In November 2023, and in anticipation of the acquisition of Who Dat, we completed a refinancing and implemented a new revolving, reserve based lending facility at reduced facility pricing, and on more flexible terms, while increasing the commitments under our facility to US$340 million. We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340 million committed under the RBL facility will become available, subject to customary conditions to draw. Deutsche Bank, Macquarie Bank, ING and Shell have participated in both of our reserve based facilities. See "Description of other financing arrangements."

We have a strong track record for conducting our operations in a safe, reliable, and environmentally responsible manner, and have ESG policies and procedures designed to achieve our carbon emissions targets.

We have a strong track record for conducting our operations in a safe, reliable, and environmentally responsible manner. We have had no recordable incidents reported over the 12 months ended December 31, 2023. We believe our safety performance is important for all of our stakeholders, and that consistent safety performance supports our long term sustainability as a business and our reputation as a corporate citizen in the markets that we operate.

We also have ESG policies and procedures in place designed to achieve our stated goals for our carbon emission performance. We have been carbon neutral for Baúna since 2021 and aim to be carbon neutral for any acquired assets within five years of purchase, including our Who Dat assets. We aim to achieve net zero by 2035 and have implemented a carbon management action plan designed to help us reach these targets. We have entered into several agreements to purchase externally verified emission reduction certificates, that help offset a portion of our forecast emissions and take emissions into account in our internal decision-making whenever we consider new investments. See "—Our strategy—We intend to continue to operate responsibly and sustainably in accordance with our sustainability strategy and objectives."

We have an experienced board and management team with deep industry expertise.

Our board and management team has significant experience in the international oil and gas industry. The board and management comprises experienced industry veterans that have worked in major oil and gas jurisdictions, including long term experience in Brazil and the United States of America. Our board and management team has guided our transition from an explorer to a producer, delivering the acquisition and development of Baúna and more recently the acquisition of the Who Dat assets.

Our management team have a track record of adding value through acquisitions, developing in-field and near-field opportunities, lowering unit costs of production, improving safety and reliability, delivering our projects on time and on budget, and increasing our reserves. Our team has delivered these outcomes while maintaining a strong balance sheet. Our chief executive officer and managing director, Dr. Julian Fowles has over 30 years of experience in oil and gas operations, including 17 years of working in the upstream sector across the globe. He previously held senior positions with Shell, Cairn India and Oil Search. Our chief financial officer, Ray Church, executive vice president commercial, Stephen Power and executive vice president technical, Roland Hamp, each also have more than 35 years of experience in the resources and energy sector.

We are geoscience and engineering led and focus on delivering growth through robust technical assessment and evaluation. We consider our technical expertise to be crucial to identifying and delivering value accretive growth opportunities.

Our strategy

Our strategy is to be a diversified, independent, offshore oil and gas production and exploration company with a focus on value creation, value accretive growth and prudent balance sheet management in the regions of Brazil and North America. We aim to be carbon neutral while targeting net zero by 2035.

We intend to grow production volumes through acquisitions, targeting opportunities in North America and Brazil, that leverage our technical expertise and teams in these regions.

We have publicly stated our 50 for 10 growth strategy, which we intend to pursue through acquisitions and bringing into production our development assets. Our 50 for 10 strategy is focused on increasing our average daily production to achieve a minimum production rate of 50,000 boepd and sustaining that level of production for a period of no less than 10 years.

We intend to continue to evaluate acquisition opportunities, focusing primarily on producing assets offshore the United States and Brazil that would increase our production, operating cash flow and profitability. Assets in these geographies would enable us to leverage our presence in Houston and Rio de Janeiro and our technical expertise in the region, as well as potentially providing opportunities to use existing infrastructure. Our acquisition of Who Dat is consistent with our strategy. However, we may also examine acquisition opportunities in other locations and at different stages of development.

We are seeking to increase our production scale and longevity and consider that targeting producing and free cash flow generating assets is a lower risk approach that will allow us to achieve these goals over the near- to medium-term. By targeting mid-life assets we are also able to leverage our in-house experience and technical capabilities to allow us to achieve high levels of production efficiency, control costs, and realize value from maturing and under-developed assets. Consistent with our acquisition of Who Dat, we aim to achieve asset life extensions and maximize economic recovery to enable future growth.

We intend to optimize and enhance the production from our existing assets through the development of in-field and near-field growth opportunities to grow our reserves and resources.

We intend to continue to enhance production and reserves from our existing asset base by further exploiting our fields in the Santos Basin and US Gulf of Mexico. Our strategy is to identify and pursue lower risk and higher margin production growth opportunities through leveraging our expertise in well understood geological conditions and maximizing the utilization of our existing infrastructure by pursuing tie back opportunities wherever possible. We have delivered production growth at Baúna through the workover and development programs, and intend to continue optimizing production through workover programs, development drilling, and infrastructure-led exploration which, if successful, can be brought into production relatively quickly and economically.

We intend to progress the potential development of Who Dat East, Who Dat South and Who Dat West, which we believe have the potential to result in a material increase in our production and replacement of our reserves. The joint venture intends to drill an appraisal well at Who Dat East starting in late April 2024. We expect an exploration well to be drilled at Who Dat South in the second half of 2024, and subject to approval by the joint venture partners, a second exploration well to be drilled at Who Dat West, also during the second half of 2024. The Who Dat East discovery and Who Dat South and West prospects, if successful, are expected to be developed through a tie back to the existing Who Dat floating production system, which has the potential to minimize additional capital expenditure requirements, while increasing our production, free cash flow, and profitability. We also continue to examine a range of development options for the Neon discovery in the Santos Basin. During the second quarter of 2024, we approved the progression of the Neon discovery into the "concept select phase", the second stage of our project maturation process.

We will strive to maintain our safety performance.

We have a record of conducting our operations in a safe, reliable, and environmentally responsible manner, and we intend to strive to maintain these standards. The safety of our people is our highest priority and is integral to the sustainability of our business.

To foster a proactive safety culture and shared 'duty of care', we, together with our principal contractors, provide safety inductions, continuous education, and training programs for all workers. We are committed to meeting and, where practical, exceeding the requirements set by relevant laws and regulations in the areas where we operate.

Despite a material increase in exposure hours at Baúna during FY23 as a result of the Baúna workover campaign, the Patola development drilling and control well drilling at Neon, we experienced a total of four reportable safety incidents and injuries during FY23. At the end of March 2024, the Who Dat floating production system facility went through more than 4,550 days since its last reportable safety incident and more than 4,250 days since its last recordable safety incident.

Our Operating Management System reflects our expectations of safety and integrity across our operated assets. The Operating Management System, which encompasses policies, guidelines, and procedures, is regularly reviewed and updated with the aim of ensuring compliance in all applicable jurisdictions.

We intend to continue to operate responsibly and sustainably in accordance with our sustainability strategy and objectives.

We recognize our responsibility to contribute to the communities and environments in which we operate, and the role that industry must play in the reduction of global carbon emissions. We maintain a robust ESG reporting framework and have a sustainability strategy that we intend to continue to execute.

A key aspect of our sustainability strategy is our carbon management action plan. We have been carbon neutral for Baúna since 2021 and aim to be carbon neutral for any acquired assets within five years of purchase, including our Who Dat assets. We aim to achieve net zero by 2035 and have implemented a carbon management action plan designed to help us reach these targets. The first step in our carbon management action plan is to eliminate or reduce emissions. An example of this was the installation of a marine vessel mooring buoy at Baúna which has reduced emissions. The second step with our carbon management action plan is to purchase carbon offsets that fully offset our scope 1 and 2 emissions. In 2022, we entered into agreements to purchase verified carbon units from Shell and Climate Impact Partners and during the second half of 2023, we entered into an agreement to purchase verified carbon units from the Hiwi REDD+ forest conservation project in the Amazon region, operated by Carbonext. The third step with our carbon management action plan is to invest in carbon sequestration projects, with a focus on nature-based solution projects in the country of our operations. We have been closely engaged with several reputable nature-based solution developers in Brazil, and we intend to continue to assess these opportunities as necessary to achieve our target of net zero (Scope 1 & 2 emissions) by 2035, and see value in investing in high quality offset producers, rather than buying offsets, over the longer term.

We intend to maintain our financial discipline and our strong balance sheet as we pursue our growth strategy.

We plan to maintain prudent financial policies and a strong balance sheet with low leverage designed to enable support from our capital providers, with the objective of being able to access capital from both debt and equity markets on reasonable market terms. We believe this approach will assist in supporting the delivery of our growth strategy.

We plan to fund growth through a combination of operating cash flow, debt, and equity where needed and appropriate. We have historically funded our acquisitions in what we believe to be a prudent manner as we did for Baúna where we funded the acquisition through cash and an equity raise, and Who Dat which we funded through cash, debt and an equity raise while maintaining low leverage. We intend to continue our financial discipline and maintaining what we believe to be balance sheet strength, and while also focusing on maintaining liquidity levels, reasonable leverage, while satisfying with our publicly stated capital allocation framework.

Our production and exploration assets

We have two main production assets, comprising six operating oil fields. Our wholly owned and operated producing asset Baúna comprises the Baúna, Piracaba, and Patola oil fields located in the southern Santos Basin, offshore Brazil. Our non-operated interests in the Who Dat producing assets comprises our interests in Who Dat, Dome Patrol, and Abilene oil and gas fields located in the US Gulf of Mexico, offshore Louisiana, United States of America.

In addition to our producing assets, we have various exploration and potential development assets adjacent to our producing Brazil and US Gulf of Mexico assets. These include, amongst others, the Neon and Goiá oil fields, which are located north-east of our Baúna assets in the Santos Basin, offshore Brazil, and are 100% owned by us, and the Who Dat East, Who Dat West and Who Dat South exploration and appraisal opportunities in the US Gulf of Mexico, in which we have a 40%, a 35% and a 30% interest, respectively.

The following map shows our assets and working interests.

Brazil

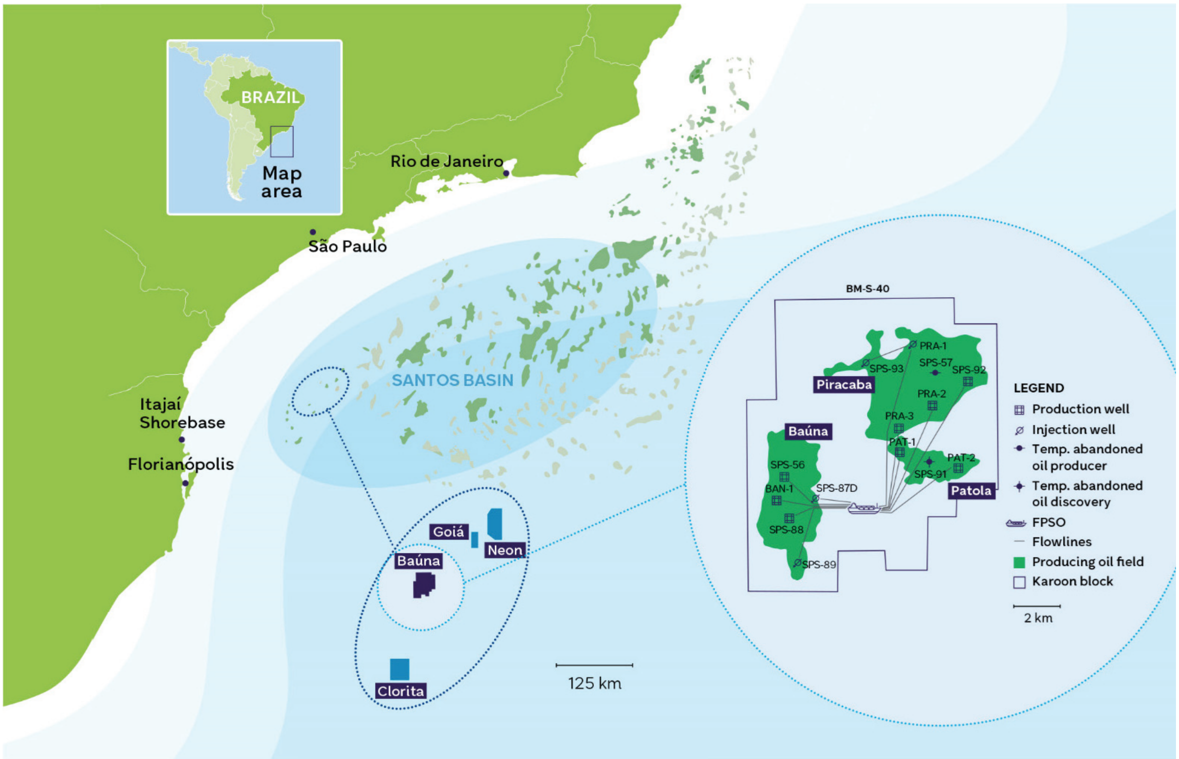
Producing assets – Baúna

Our core producing asset in Brazil is our 100% owned and operated BM-S-40 concession agreement in the southern Santos Basin. The BM-S-40 concession agreement comprises the Baúna, Piracaba and Patola oil fields, all of which are producing. We refer to the Baúna, Piracaba and Patola oil fields collectively as the Baúna Project or Baúna. Baúna is a conventional offshore oil operation, in approximately 300 meters of water, located approximately 210 kilometers offshore Brazil.

Petrobras SA discovered the Baúna and Piracaba fields in 2008. Production commenced in 2013, and in 2019, Petrobras listed the Baúna assets for sale. We acquired and assumed operatorship of Baúna from Petrobras in November 2020 for US$380 million plus additional oil-price related contingent payments of up to US$285 million plus accrued interest. To date, we have paid US$170.5 million of this obligation, which includes US$14.5 million of interest. This acquisition was transformational for us as we evolved from an exploration company to a producer and developer. The transfer of operatorship from Petrobras to us occurred with no material safety incidents or interruption to production.

In February 2022, we entered into a marketing and offtake agreement with Shell Western Supply and Trading Ltd (a member of the Royal Dutch Shell Plc group) or SWST. All of our production from Baúna is sold under this agreement, which we renewed in November 2023. For further details on this agreement, see "—Products, sales, and marketing." We also agreed to acquire emission reduction credits from SWST to offset approximately 60% of FY21 to FY29 Scope 1 and Scope 2 emissions from Baúna. These are verified by global certifier of voluntary carbon offsets, VERRA. As a result of these credits, and previous carbon credits that we acquired in November 2021, our Baúna assets are carbon neutral.

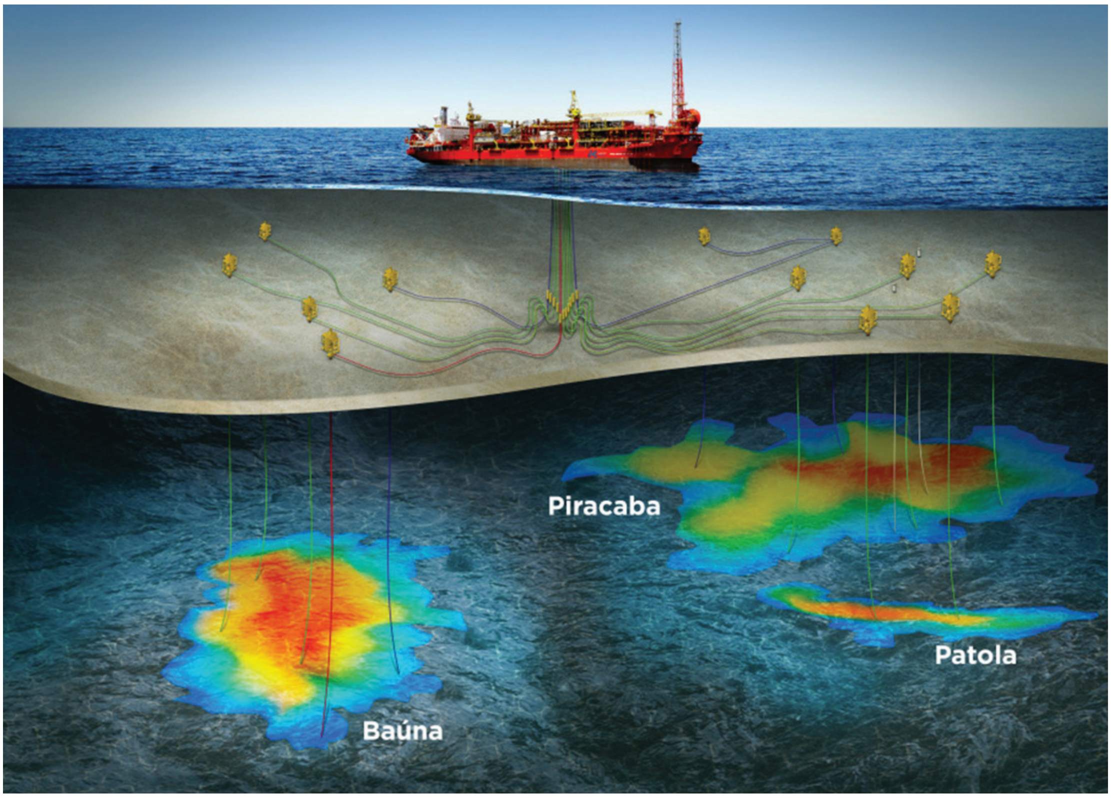
The following map provides a detailed view of our interest in the Baúna assets.



Baúna is located in the southern post-salt region[28] of the Santos Basin and comprises Oligocene reservoirs with high porosity and permeability. See also "Regulatory overview—Regulatory overview—Brazil—Pre-salt and strategic areas." Baúna comprises seven producing wells (and one additional production well that is currently shut in) which are connected through sea-bed flowlines to a floating production, storage and offloading facility, the *Cidade de Itajaí*. The floating production, storage and offloading facility is owned by Altera & Ocyan, a joint venture formed between infrastructure service providers Altera and Ocyan. See "—Floating production, storage, and offloading facility, *Cidade de Itajaí*" below for additional information on the *Cidade de Itajaí*.

28 Post-salt areas overlie an existing salt layer and contain stratigraphically younger hydrocarbon reservoirs compared to pre-salt areas.

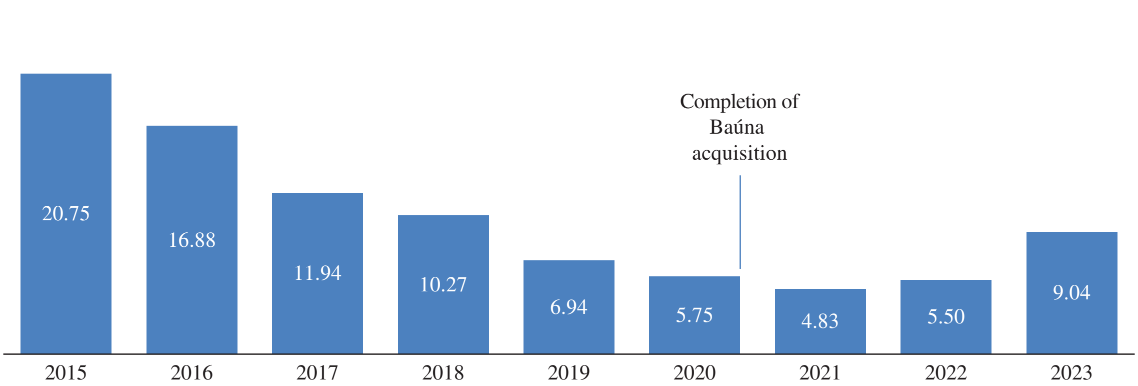
The following graphic shows our Baúna reservoirs, subsea infrastructure and the *Cidade de Itajaí.*



Operational overview

Since taking operatorship in November 2020, we have increased the average daily production rate from 14,800 bopd during the time period from November 7, 2020 to December 31, 2020 to a peak average daily production of 34,500 bopd in July 2023. During the quarter ended December 31, 2023 our average daily production rate was 27,500 bopd, representing an increase by 86% compared to the period from November 7, 2020 to December 31, 2020. The following chart illustrates the long term production profile of Baúna and the improvements achieved due to our investment in Baúna through the workover program and Patola development.

Baúna Production History (MMbbl)[29]



29 Source: Historical data prior to our acquisition provided by Petrobras and as published by ANP.

We identified enhancement opportunities in Baúna which we believed would increase production and reserves and, following 18 months of planning, we undertook a workover program at Baúna from May 2022 to September 2022. The workover program comprised the installation of new electric submersible pumps in two wells (PRA-2 and SPS-92) and the installation of gas lift equipment in a third well (SPS-56). As a result of the workover program, we materially increased production.

In June 2021, we took the final investment decision to proceed with the development of the Patola field. We commenced work after the Baúna oil field workover campaign was completed in September 2022. The Patola development comprised drilling two production wells, installing wellheads and trees and putting subsea production infrastructure in place, including flowlines and umbilicals that connect the wells to the Baúna floating production, storage and offloading facility. We achieved first oil in March 2023, with the Patola development resulting in a material increase in our production and reserves.

We have a track record of delivering enhancements in accordance with our planning, with both the workover program and Patola development being delivered safely, on time, and within budget. The below chart shows the increase in our 2P reserves at Baúna (MMbbl) following our workover and Patola development campaigns.

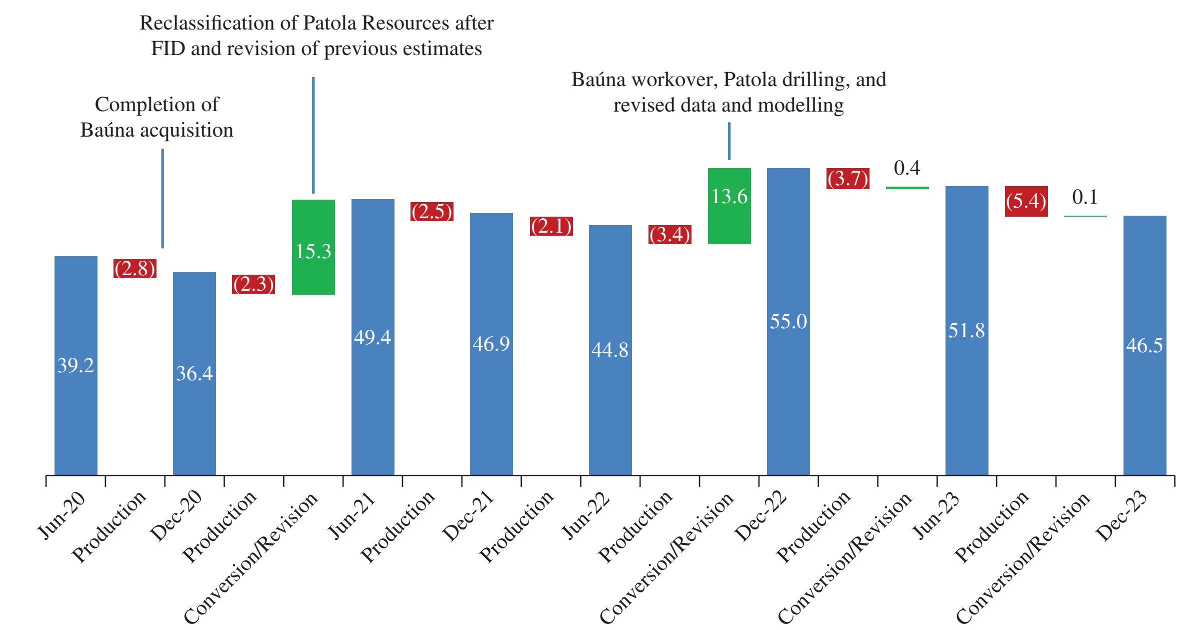
One of our wells at Baúna (SPS-88) has been unable to resume normal production since late 2023 due to a mechanical blockage in the well's gas lift valve. We expect to undertake a workover program in an attempt to return the well to normal production in the third quarter of 2024, subject to regulatory approvals and contracting a suitable vessel.

Floating production, storage, and offloading facility, Cidade de Itajaí

Our floating production, storage, and offloading facility, *Cidade de Itajaí* was built in 1985 and converted to a floating production, storage and offloading facility in 2012. It is owned by Altera & Ocyan and subject to at least annual certification by DNV, a leading classification society and recognized advisor for the maritime industry, and regular review by the relevant regulators.

It has fluid handling capacity of approximately 80,000 barrels of liquid per day and storage capacity of approximately 631,000 bbl of oil. Other than during scheduled shutdowns, operations run 24 hours a day with separate crews working on two weeks on/two weeks off basis. We have technical representatives from Karoon on board the *Cidade de Itajaí* at all times.

Increase in Baúna 2P Reserves (MMbbl)



We have chartered the *Cidade de Itajaí*, until 2026 with two one-year extension options by mutual agreement. We are required to notify Altera & Ocyan one year in advance if we want to exercise these extension options. We have also commenced discussions to extend our contract with Altera & Ocyan until 2032, which is in line with current reserves estimates for Baúna. We are currently assessing whether it is possible to extend the field life of the Baúna assets until 2038 and to commercialize the associated contingent resources we estimate to be present in these fields. Any life extension is subject to contractual negotiations with Altera & Ocyan, and receiving regulatory approvals, including from the Brazilian naval authority and the Brazilian Petroleum Agency, which is our primary regulator and is referred to as ANP. We have assessed potential work required on the subsurface infrastructure and existing wells, and expect to define the scope of any potential life extension project in the second half of 2024.

Our contractual arrangements for the *Cidade de Itajaí* consist of a bareboat charter with Altera & Ocyan and a separate contract for operating services with OOG-TKP, an affiliate of marine transportation company Teekay.

Under the charter, Altera & Ocyan is in charge of the general maintenance of the facility, including in relation to safety equipment, telecommunications systems, the facility's helipad and its insurance. Altera & Ocyan is also responsible for any replacement costs or costs associated with repairs. The costs for our charter are readjusted on an annual basis and tied to the US consumer price index. The charter contract grants us termination rights if, among other circumstances, Altera & Ocyan fails to comply with contractual terms that may significantly impact the performance of the charter agreement or outsources its obligations without our prior written consent. Altera & Ocyan would be able to terminate our charter contract if we had overdue payments outstanding for more than 90 days, subject to certain exceptions, or the operating services contract were to be terminated.

Under the operating services contract, OOG-TKP provides services in relation to the handling, processing and storage of crude oil; supplying of crew, installation of spare parts and maintenance of equipment on board the *Cidade de Itajaí,* water injection, gas lift, gas export and the transfer of stabilized crude oil from the *Cidade de Itajaí* to shuttle tankers. In addition, OOG-TKP is in charge of the implementation and supervision of positioning and ballasting of the facility. The costs for OOG-TKP's operating services are readjusted on an annual basis and tied to the US consumer price index. The operating services contract grants us termination rights if, among other circumstances, OOG-TKP fails to comply with contractual terms that may significantly impact the performance of the agreement, outsources its obligations without our prior written consent or fails to comply with providing proof of the payment of its labor rights obligations. OOG-TKP would be able to terminate the contract if we had overdue payments outstanding for more than 90 days, subject to certain exceptions, we were to suspend the execution of the operating services by written order for a period exceeding 120 days or fail to make the area, location or equipment available that is necessary for the execution of the operating services within contractual deadlines.

Recently, we have been working with Altera & Ocyan to address a range of operational issues with the *Cidade de Itajaí* where we have sought improvements, including adding redundancy to certain systems the failure of which could result in an interruption of production until they are repaired. We have also notified Altera & Ocyan of a number of non-compliances for which we believe we are entitled to receive contractual penalties. While we believe that we and Altera & Ocyan are working constructively to resolve the remaining operational issues, a failure by Altera & Ocyan to address the remaining issues would result in an elevated risk of production interruptions. See also "Risk factors—Risks relating to our industry and operations—Our Brazilian production depends on a single floating production, storage and offloading facility owned by Altera & Ocyan."

We are currently planning to undertake additional enhancements to improve asset integrity, operational efficiency, and emissions in respect of the floating production, storage, and offloading facility, to strengthen our overall performance and sustainability score. We also intend to increase our produced water treatment capacity. The next planned maintenance shutdown has been scheduled for May 2024, during which we plan to conduct an inspection of the valves, tanks and hulls as well as further pipe inspections and integrity activities for up to three weeks.

Production

The following table summarizes key operating and production metrics for our Baúna assets for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
Production (MMbbl)	3.14	4.64	7.04	3.37	5.38
Unit production cost (US$/bbl)[(1)]	25.11	25.36	15.75	17.25	11.09
FPSO efficiency (%)[(2)]	95%	98%	82%[(3)]	95%	92%

Notes:

(1) Unit production cost is a non-IFRS figure. See "Non-IFRS financial measures" for further details.

(2) We calculate the efficiency rate of the floating production, storage and offloading facility as actual production divided by our reservoir production forecast, limited to 100%.

(3) In March 2023 following the identification of a gas leak resulting in a temporary shutdown, we decided in consultation with Altera & Ocyan to undertake a comprehensive inspection of the pipework on the floating production, storage, and offloading facility. All identified repairs, maintenance or replacements were conducted over a six-week period, resulting in lower facility efficiency rate in the twelve months ended June 30, 2023.

During FY22 production at Baúna benefited from 98% facility efficiency rate. We produced 4.64 MMbbl from our Baúna assets in FY22, compared to 3.14 MMbbl in FY21. This increase reflected our first full year of operations since the acquisition of Baúna in November 2020.

As a result of the completion of the Baúna oil field workover campaign and the development of Patola, oil production was 52% higher at 7.04 MMbbl in FY23 compared to 4.64 MMbbl in FY22, despite the six-week unplanned shut down of the production facility. Both the workover and the Patola development delivered incremental production above expectations, resulting in a peak average daily production of 34,500 bopd in July 2023.

The facility efficiency rate during FY23 was 94% over the first nine months of FY23. In March 2023, we had to shut down production on the floating production, storage and offloading facility, due to a hydrocarbon leak from pipework located within the facility's gas flaring system. We were able to rapidly isolate and repair the leak but decided, together with the facility operator, Altera & Ocyan, to undertake a comprehensive inspection of the facility's hydrocarbon processing system pipework. We subsequently inspected a total of 783 pipes and valves repaired or replaced more than 120 parts over a six-week shutdown period. We notified ANP, about the gas leak and repair campaign. ANP was supportive of the production restart in May 2023. Our floating production, storage, and offloading facility has historically achieved high levels of efficiency, averaging 95% over the period from November 7, 2020, when we commenced as operator of Baúna, to December 31, 2023, excluding the March 2023 shutdown, and 91% including the shutdown. Despite our production shut down from the end of March 2023 until May 2023, we produced 7.04 MMbbl from our Baúna assets in FY23.

During TY23, our facility efficiency rate was 92% and we produced 5.38 MMbbl of oil from Baúna compared to 95% and 3.37 MMbbl of oil during HY23.

Products, sales, and marketing

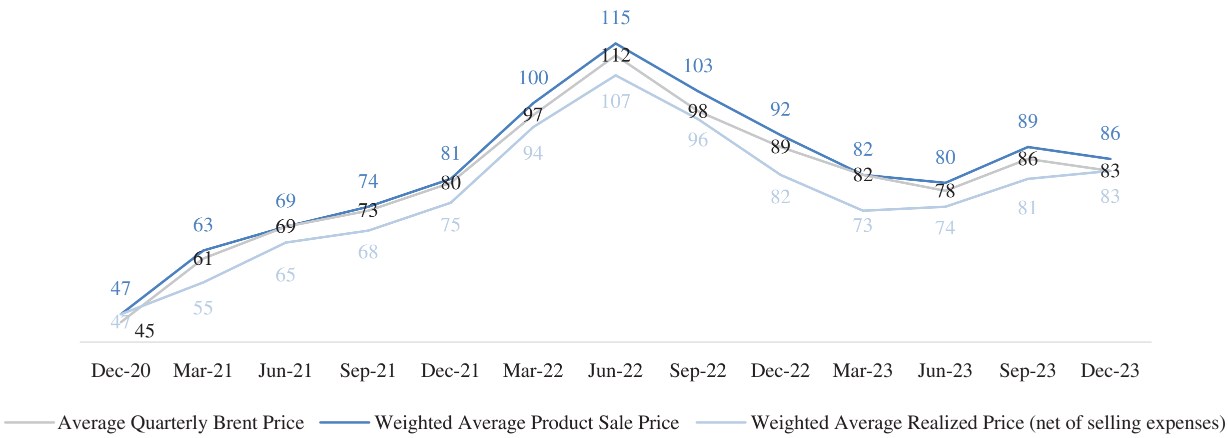
Baúna produces a light sweet crude oil that is high quality, as reflected in its sales prices, with an API between 33 and 38 degrees. Our production is sold to SWST under our offtake and marketing agreement, is then marketed by SWST, and typically sold to a range of customers in South America, North America, Europe and Asia. We realize a price equal to the published Brent crude oil price at the time of sale, adjusted for a negotiated price differential and freight logistics and associated costs. Since acquisition of Baúna, we have averaged a sale price of approximately US$84.92 per bbl which represents a premium to the average Brent price on a delivered basis and which corresponds to an weighted average realized price (net of selling expenses) discount of 4.7% to Brent over the corresponding period.

Our agreement with SWST will expire on the later of (i) the date on which we cancel all commitments under our RBL facility, (ii) three years after the end of the "Pre-Existing Term", which is the later of December 9, 2025 or the delivery of 28.6 million barrels of oil pursuant to the agreement, and (iii) when a further 20.0 million barrels of oil have been delivered pursuant to the agreement after the end of the Pre-Existing Term. As of March 31, 2024, 21.9 million barrels of oil have been delivered pursuant to this agreement. Following an amendment to our offtake and marketing agreement with SWST during TY23, SWST may require us to undertake our own oil transportation activities. If this occurs, the freight logistics charges that are netted against our revenue will be reduced, though our cost of sales would increase.

Under this agreement, SWST is required to use reasonable endeavors to maximize the price payable to us. Each party can terminate the agreement if the other party commits a fraudulent or an unremedied willful breach of the agreement or fails to satisfy a payment demand for more than 28 days after provision of a notice of default.

The chart below shows the average quarterly published Brent crude oil price, our average sale price and our weighted average realized price (net of selling expenses), each in US$/bbl.

Average Quarterly Brent Price, Weighted Average Product Sale Price, and Weighted Average Realized Price (net of selling expenses) (US$/bbl)[30]



Since our acquisition of Baúna, we have sold more than 45 cargoes, to 11 refineries that are located across four continents. Our strategy involves continuing to develop the global market for Baúna crude so as to optimize our realized price.

The crude oil is either offloaded from the Baúna floating production, storage and offloading facility into SWST-operated shuttle tankers and transported to Uruguay or directly transferred by us to SWST through a ship-to-ship oil transfer in the Port of Santos, Brazil.

The following table summarizes key sales metrics for our Baúna assets for FY21, FY22, FY23, HY23 and TY23.

	FY21	FY22	FY23	HY23	TY23
Sales volume (MMbbl)	2.90	4.54	7.06	3.41	4.97
Weighted average realized oil price (net of selling expenses) (US$/bbl)	59.00	84.74	80.20	87.86	82.22
Revenue (US$ million)	170.8	385.1	566.5	299.4	409.1

30 The average Brent price for the quarter ended December 31, 2020 reflects the average published Brent crude oil price over the quarter ended December 31, 2020, noting that our operations commenced on November 7, 2020. We shipped our first cargo in December 2020. Karoon realized price is defined as weighted average realized price (net of selling expenses). Product sale price is defined as the weighted average actual price achieved for Baúna crude based on an agreed premium or discount benchmarked to the Brent crude oil price.

We lifted nine oil cargoes from our Baúna assets in FY22, totaling 4.54 MMbbl, compared to six cargoes lifted in FY21, totaling 2.90 MMbbl. This increase reflected our first full year of operations since the acquisition of our Baúna assets in November 2020 and high facility efficiency rates. In FY22 we realized a weighted average realized price (net of selling expenses) of US$84.74/bbl, compared to US$59.00/bbl in FY21, due to stronger global crude oil prices and the expansion of buyer markets for Baúna crude, which since include Europe, Asia and North and South America.

We lifted 15 oil cargoes from our Baúna assets during FY23, totaling 7.06 MMbbl, representing an increase of 52% compared to FY22. The weighted average realized oil price (net of selling expenses) during FY23 was US$80.20/bbl, compared to US$84.74/bbl in FY22, reflecting weaker oil demand due slowing global economic growth.

We lifted 10 oil cargoes from our Baúna assets during TY23, totaling 4.97 MMbbl. We realized a weighted average realized oil price (net of selling expenses) of US$82.22/bbl during TY23, compared to US$87.86/bbl in HY23, reflecting strong demand for Baúna light sweet crude, with cargoes sold to various refineries in Europe, Asia and North and South America.

Licensing and royalties

The BM-S-40 concession agreement grants us exploration and production rights for our Baúna assets until 2039. We pay royalties to the Brazilian federal government. These are divided into three tiers, 10%, 7.5% and 5% and based on a monthly baseline production decline model approved by ANP. See "Regulatory overview—Regulatory overview—Brazil—Concession bids—Government participation." During the initial period of our concession agreement, our royalties were set at 10% of our production. Since October 2022, our rates vary between 5% and 7.5% of production. For our Brazilian assets, royalties paid are deducted as part of our cost of sales. See "Management's discussion and analysis of financial condition and results of operations—Overview—Key income statement line items—Cost of sales." In addition, we pay a special participation fee on a quarterly basis when production in any given quarter exceeds 300,000 m^3. If we reach this trigger, we are also required to invest 1% of our gross revenue for the quarter into research and development. In the quarter ended December 31, 2023, our production on a cubic meter basis was 416,670 m^3.

Baúna reserves and contingent resources

The following tables sets forth our 1P, 2P and 3P net oil reserves and our 2C contingent resources for our Baúna assets as of December 31, 2023.[31] For additional information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

Reserves

	As of December 31, 2023		
	1P	**2P**	**3P**
		(MMbbl)	
Baúna, Piracaba and Patola	37.1	46.5	55.8
Total (MMbbl)	**37.1**	**46.5**	**55.8**

31 We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserve reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's audit report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

2C Contingent resources

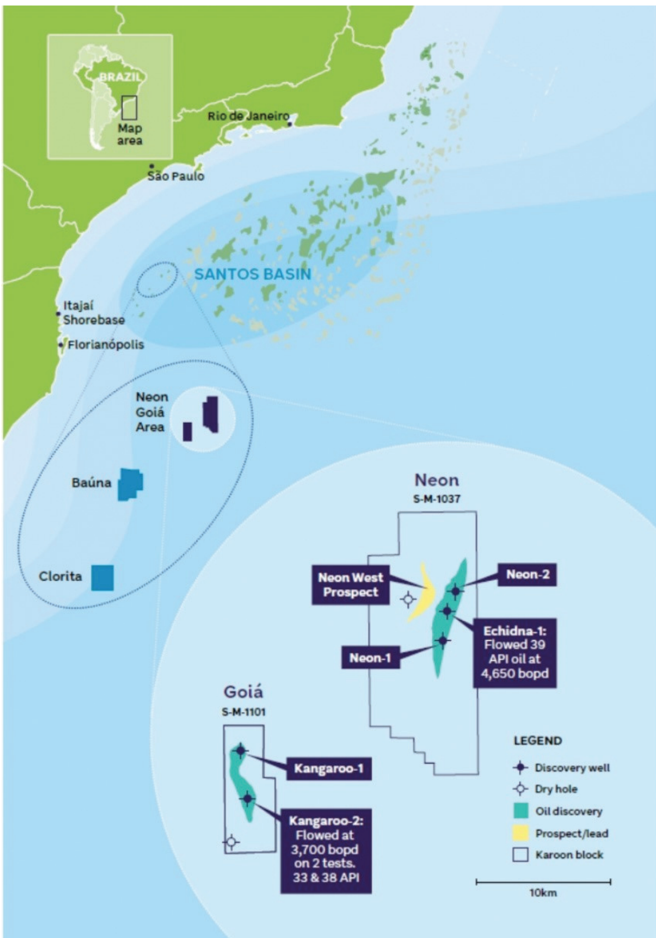
	As of December 31, 2023
	2C
	(MMbbl)
Baúna, Piracaba and Patola	10.9
Total (MMbbl)	10.9

As of December 31, 2023, we had committed a minimum of US$27.5 million towards future exploration activities in connection with our Baúna assets. We also continue to explore and add reserves in our other Brazil operations. See also "Management's discussion and analysis of financial condition and results of operations—Off-balance sheet arrangements—Commitments for expenditure."

Development and exploration assets

In addition to Baúna, we also own and operate several development and exploration blocks in the Santos Basin. These include block S-M-1037, which contains the discovered Neon oil field and the Neon West prospect, and block S-M-1101 which contains the discovered Goiá oil field, both of which are located north-east of Baúna. We also 100% own and operate block S-M-1537, which contains the Clorita prospect, south of Baúna, and in December 2023, we successfully participated in a government bid round to acquire 100% interests in two deepwater blocks, S-M-1356 and S-M-1482, southeast of Baúna. We expect the Brazilian government to formally grant these two blocks to us during the second quarter of 2024. We hold 'Operator A' status in Brazil, as confirmed by the regulatory authorities, which certifies us as meeting the requirements to drill in deepwater blocks.

The following map shows the location of our development and exploration assets in Brazil.



Neon

Neon (formerly known as Echidna) is located 60 kilometers north-east of the Baúna oil field in block S-M-1037 in the Santos Basin, which we were awarded through a government tender in 2007. We discovered Neon with the Echidna-1 exploration well in 2015. The discovery well encountered 100 meters of oil-bearing reservoir and on test, flowed 4,650 bopd of 39 degrees API oil. During April 2024, we approved the progression of the Neon discovery into the "concept select phase", the second stage of our project maturation process.

Following successful tests during initial exploration, we conducted substantial analysis, engineering and technical work on a potential development of Neon in order to assess the commercial potential of the discovery. We drilled two control wells at Neon in January 2023 and March 2023 with both wells intersecting hydrocarbon-bearing reservoirs consistent with pre-drill expectations. This result has reduced our uncertainty around key reservoir parameters. The Neon-1 well confirmed 39 degrees API oil and oil-water contacts closely aligned to our seismic predictions, the Neon-2 well confirmed 33 degrees API oil and thickened reservoir sections in cross-fault and northwestern regions.

As a result of the confirmed Neon-1 and Neon-2 oil discoveries, we reassessed our volume estimates, resulting in a 9% increase in our estimates of Neon's 2C contingent oil resources in FY23. We are currently conducting the technical and commercial feasibility studies for a potential Neon development. The technical aspects include detailed subsurface modelling, integrating seismic reprocessing, core and fluid sample analyses.

We believe that the undrilled Neon West prospect is structurally and stratigraphically analogous to Neon. We have estimated prospective resources for the Neon West prospect due to its close proximity to the Neon discovery and its higher probability of technical and commercial viability in the event of resource confirmation.

The following table sets forth our 2C contingent resource estimates for our Neon oil field as of December 31, 2023. For additional information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

Contingent resources

	As of December 31, 2023
	2C
	(MMbbl)
Neon	60.1
Total (MMbbl)	60.1

Goiá

Goiá is located 10 kilometers south-west of Neon and 50 kilometers north-east of Baúna in block S-M-1101 in the Santos Basin. We were awarded a 100% interest in the block through participation in a government tender in 2007. We discovered oil accumulation through our Kangaroo-1 exploration well in 2013 and appraised it with an additional well (Kangaroo-2) which spudded in November 2014. Initial tests for the Kangaroo wells showed the potential for high initial flow rates of 33 and 39 degrees API oil. As a result of these tests, we were able to assign contingent resource estimates to Goiá in 2015.

We are currently evaluating the Goiá oil discovery, together with nearby opportunities, such as Neon West.

The following table sets forth our 2C contingent resource estimates for our Goiá oil field as of December 31, 2023. For additional information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

Contingent resources

	As of December 31, 2023
	2C
	(MMbbl)
Goiá	27.0
Total (MMbbl)	27.0

Clorita

Clorita is located 50 kilometers south of our Baúna in block S-M-1537 in the Santos Basin. We hold a 100% equity interest in the block. We are currently undertaking desktop geological and geophysical studies, including petroleum system modelling, aimed at better defining the Clorita prospect. We hope to find the same quality Oligocene oil-prone turbidite reservoirs as the Baúna field.

In addition, we are evaluating the potential value of resistivity based 'controlled source electromagnetics' methods to help identify possible reservoir intervals.

S-M-1356 and S-M-1482

We successfully bid for a 100% interest in two deepwater blocks, S-M-1356 and S-M-1482, in the Santos Basin in December 2023. These two blocks lie approximately 80 kilometers southeast of Baúna. Formal granting of these two blocks is subject to certain conditions that we expect to meet during the second quarter of 2024.

United States of America

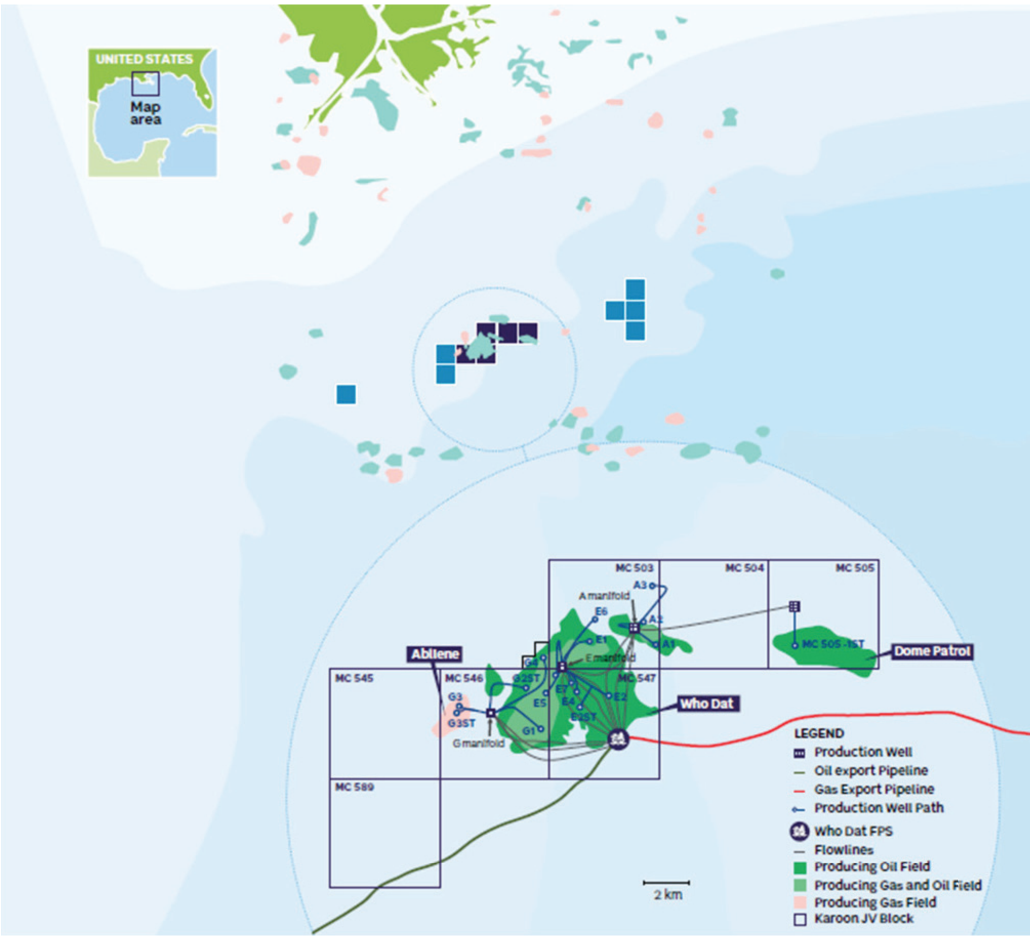
Producing assets – Who Dat

Our core producing asset in the United States of America is our 30% non-operated interest in the producing Who Dat and Dome Patrol oil and gas fields, and approximately 16% working interest in the producing Abilene field. We refer to the Who Dat, Dome Patrol, and Abilene oil and gas fields collectively as Who Dat, or the Who Dat assets. The Who Dat assets are a conventional deepwater oil and gas operation, located in approximately 800 meters of water, offshore Louisiana, which management believes is a high quality, low cost operation.

LLOG acquired its initial interest in the Who Dat field in 2005 and began drilling the first Who Dat well in 2007. A final investment decision was taken in 2010 and initial production started in 2011. We acquired our working interest in the Who Dat assets from LLOG in December 2023 for US$720 million. As part of our acquisition of the Who Dat assets, we also acquired varying interests in adjacent acreage, including the Who Dat East (40% interest), Who Dat West (35% interest) and Who Dat South (30% interest) exploration and appraisal opportunities and agreed to fund up to US$39.2 million in additional payments relating to the appraisal and exploration of Who Dat East and Who Dat West. We funded this acquisition through a A$480 million equity raising, a US$274 million drawdown of our RBL facility and existing cash.

We completed the acquisition on December 21, 2023 and have included our share of production from the Who Dat assets in our production figures from that date. Under the agreement under which we purchased our interests, we agreed to an effective date of October 1, 2023, coinciding with the annual operating plan cycle. This meant that the purchase price was adjusted to give us the economic benefits and obligations of ownership from October 1, 2023 onwards, including revenue, operational expenses and capital expenses. We were entitled to our share of production and participated in joint venture cash calls from December 21, 2023 onwards.

The following map shows the location of our US Gulf of Mexico assets in the United States.



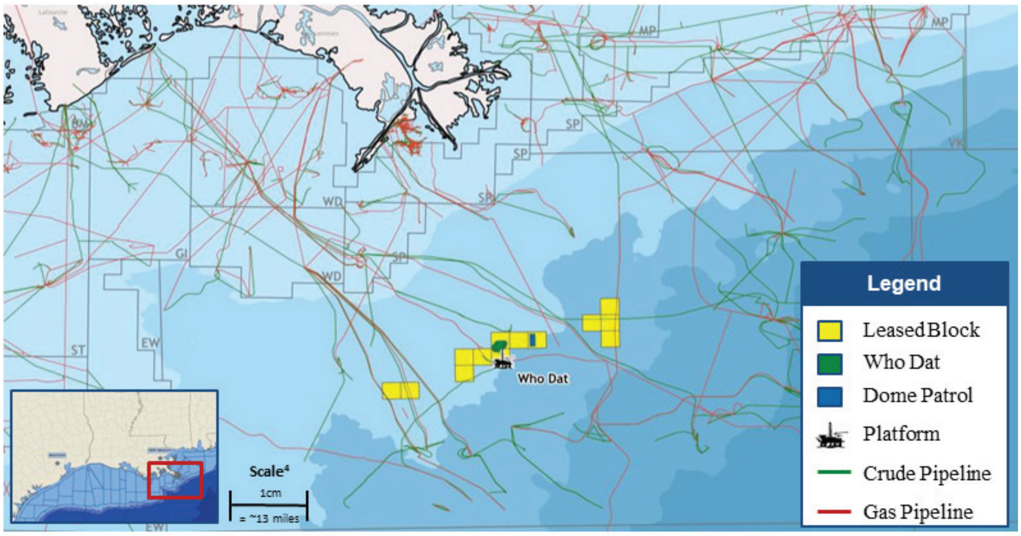
The producing Who Dat assets are located in the Mississippi Canyon blocks 503, 504, 505, 546 and 547. The Who Dat subsea infrastructure includes 13 producing wells, connected to four manifolds, of which three are in the Who Dat field and one at the Dome Patrol field, with associated flowlines. These include smart completions connected to the floating production system facility via umbilicals. Two lateral export pipelines connect to the Mars pipeline for oil and the Canyon Chief pipeline for gas, through which the oil and gas is transported onshore for sale.

All three fields produce through the Who Dat platform, which is a floating production system semi-submersible moored around 800 meters deep offshore in Mississippi Canyon block 547. The floating production system facility has a nameplate capacity of 40,000 bopd and 150 MMscfpd. The Who Dat floating production system historically has had a stable and reliable operating profile. Since commercial production began in 2011 to March 31, 2024, based on the proportion of days with recorded production in the year and excluding scheduled downtime, the facilities have achieved an average uptime of 94%. During the quarter ended December 31, 2023, the joint venture partners undertook remediation works for corrosion under insulation on an oil treater degasser, resulting in a lower facilities uptime of 91%.

The leases for most of our producing Who Dat assets are held-by-production, which means that our joint venture can continue with drilling and production activities as long as we are meeting required minimum production limits. See also "Regulatory overview" and "—Our concession agreements and leases."

Within the United States, the Gulf of Mexico is expected to account for approximately 17% of total crude oil production in 2024 and approximately 8% of all offshore liquids produced globally. As such, it has extensive existing infrastructure, which allows hydrocarbons to be extracted at a comparatively low CO_2e/boe[32].

The following map shows the US Gulf of Mexico and its surrounding infrastructure.

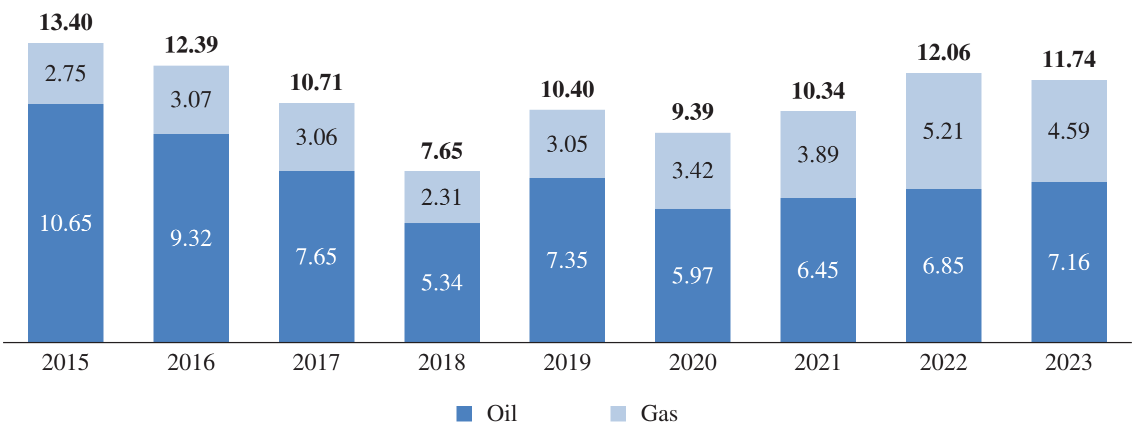


Operational Overview

The subsurface geology of the Who Dat assets is defined by high quality turbidite reservoirs, high porosity and permeability. The reservoir is characterized by stacked pay opportunities, which refers to the presence of multiple potential producing formations beneath a given surface location. We believe these opportunities allow for relatively low cost development and replacement of reserves, which supports us in prolonging the life of our producing fields. Historically, the Who Dat assets have exhibited predictable and reliable production which has been achieved through LLOG's in-field and near-field development program.

The below chart shows the overall gross historical production performance of the Who Dat assets by calendar year in MMboe.[33]

Who Dat Historical Production (MMboe)[34]



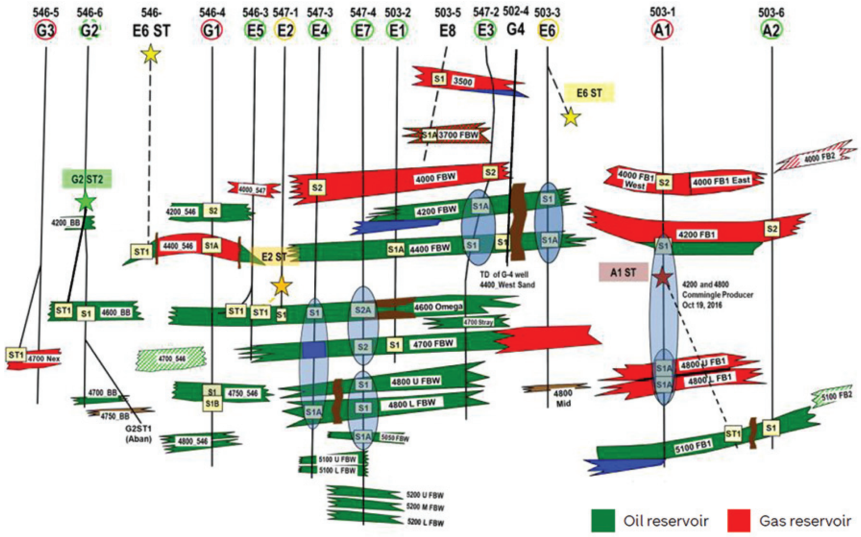
32 Wood Mackenzie Consulting, Karoon Energy, Brazil and US Gulf of Mexico Offshore Market Assessment, April 2024. See Annex B.

33 Source: Historical production data provided by LLOG.

34 Historical production shown on a gross basis.

Who Dat currently has 14 producing wells (and one non-producing well). A new well, a sidetrack and a subsea pump were brought online during the second half of 2023. Some wells are produced intermittently for reservoir management purposes or may be shut in from time to time for other reasons. These added approximately 10,000 boepd (gross) to overall production or 2,400 boepd to our share of production on a NRI basis. A sidetrack of one of the wells encountered a shallower reservoir as well as the original deeper target. As a result, completion plans were amended to enable production from either reservoir zone into the Who Dat floating production system facility. Subject to testing and determining optimal reservoir management strategies, we expect the shallow zone to provide incremental production and reserves. A new well and a sidetrack within the Who Dat field were brought online during February 2024. We estimate that this new well and sidetrack will lead to additional 6,000-8,000 boepd (gross), or 3,000 boepd of our share of production on a NRI basis.

The chart below shows the Who Dat reservoir unit cross section.



Production

The following table summarizes, on a NRI basis, our historical key operating and production metrics for our Who Dat assets for TY23 and *pro forma* operating and production metrics for FY23 and TY23 as if we had acquired our share in the Who Dat assets on July 1, 2022. See "Unaudited pro forma combined financial information" and "Selected unaudited pro forma combined financial information."

	Historical(1)	**Pro Forma(2)**	
	TY23	**FY23**	**TY23**
Oil production (MMbbl)	0.06	1.62	0.93
Gas production (MMboe)	0.03	1.12	0.52
NGL production (MMboe)	0.0	–	0.0
Total production (MMboe)	**0.09**	**2.74**	**1.45**
Unit production cost (US$/boe)(3)	7.09	10.42	11.80
Production facility uptime (%)(4)	96%	99%	96%

Notes:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

(2) Includes our share in the Who Dat assets on a NRI basis as if we had acquired our share in the Who Dat assets on July 1, 2022.

(3) Includes processing and transportation expenses.

(4) We calculate the floating production system uptime rate for Who Dat by dividing the number of days with production by the number of days in the given time period, excluding scheduled downtime.

The following table summarizes the overall gross historical performance of certain key operating and production metrics for our Who Dat assets for FY23, HY23 and TY23.

	FY23	HY23	TY23(1)
Oil production (MMbbl)	6.74	3.36	3.78
Gas production (Bcf)	29.53	15.97	13.96
NGL production (Mgal)	–	–	0.0
Total production (MMboe)	**11.66**	**6.02**	**6.10**
Production cost (US$/boe)(2)	10.42	10.26	11.80
Production facility uptime (%)	99%	99%	96%

Notes:

(1) We acquired the Who Dat assets on December 21, 2023.

(2) Production cost represents the direct operating expenses per boe. Includes processing and transportation expenses.

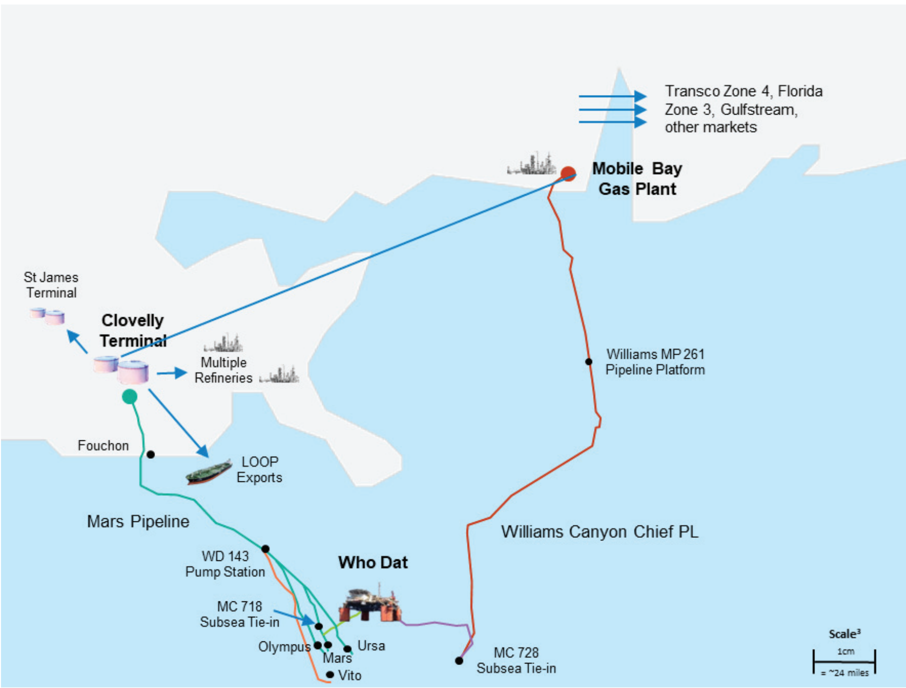
Products, sales and marketing

The oil and gas production from our Who Dat assets is processed through the Who Dat floating production system facility platform and then transported to our offtakers through common carrier pipelines.

Oil is transported via the Mars pipeline, a common carrier system operated by a subsidiary of Royal Dutch Shell Plc, through a Who Dat-owned lateral pipeline. The Mars pipeline has published rates to multiple terminals, refineries and the Louisiana offshore oil port for export. Oil from Who Dat is Mars grade and sold at a price equal to WTI crude oil as adjusted for the published Mars differential, a key reference price of crude oil within the US Gulf. This provides us with the ability to sell our production to multiple potential counterparties and refineries and diversify our offtakers, whilst optimizing our realized price.

Gas is transported through a Who Dat-owned lateral pipeline, into the Canyon Chief pipeline, an offshore gathering system operated by Williams and then delivered to the Transcontinental Gas pipeline. The Transcontinental Gas pipeline provides service to the Williams Mobile Bay gas plant, and then into multiple onshore markets. Who Dat gas is typically priced off Platt's Florida Zone 3 or Transco Zone 4 index, which are reference prices for gas in the Louisiana/Southeast region of the United States.

The chart below shows our pathway to market for Who Dat.



Following our acquisition until March 31, 2024, LLOG sold our share of the oil and gas produced from Who Dat on our behalf pursuant to a transitional services agreement.

Since April 1, 2024, we have sold our share of crude oil to BP Products North America Inc. under a month-to-month evergreen crude oil purchase agreement at a price equal to the forward price for the following month for WTI crude oil, adjusted for the published Mars differential, a monthly negotiated price differential, transportation costs and a quality adjustment reflecting the quality of the Who Dat crude oil compared to other crude oil transported on the Mars pipeline.

We sell our share of natural gas on a six-months seasonal contract basis to BP Energy Company under a gas purchase contract at a price equal to the Platt's Florida Zone 3 index, adjusted for a negotiated price differential and the cost of transportation and processing. This contract may be terminated by either party on providing 30 days of written notice.

We sell our share of natural gas liquids under a life-of-asset sales agreement to Williams Field Services, a U.S. based natural gas infrastructure provider, at prices linked to the Mont Belvieu index as adjusted for the cost of transportation and fractionation. This agreement terminates upon the permanent cessation of production from all dedicated leases. In addition, our joint venture is able to terminate the agreement if, among others, technical specifications in relation to the gas gathering system are not met.

We expect to finalize further offtake and marketing agreements through 2024, which would give us additional options to optimize sales. See also "Management's discussion and analysis of financial condition and results of operations—Overview—Key income statement line items—Revenue."

The following table summarizes, on a NRI basis, our historical key sales metrics for our Who Dat assets for TY23, and *pro forma* sales metrics for FY23 and TY23 as if we had acquired our share in the Who Dat assets on July 1, 2022. See "Unaudited pro forma combined financial information" and "Selected unaudited pro forma combined financial information."

	Historical(1)	**Pro Forma**(2)	
	TY23	**FY23**	**TY23**
Oil sales volume (MMbbl)	0.06	1.60	0.90
Gas sales volume (Bcf)	0.03	5.88	2.78
NGL sales volume (Mgal)	–(3)	5.15	2.46
Total Sales volume (MMboe)	**0.09**	**2.70**	**1.42**
Weighted average realized oil price (net of selling expenses) (US$/bbl)	70.59	80.08	81.77
Weighted average realized gas price (net of selling expenses) (US$/mcf)	2.78	5.84	3.17
Weighted average realized NGL price (net of selling expenses) (US$/gal)	–(3)	0.86	0.71
Weighted average realized price (US$/boe)	**42.22**	**61.73**	**59.19**

Notes:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

(2) Includes our share in the Who Dat assets on a NRI basis as if we had acquired our share in the Who Dat assets on July 1, 2022.

(3) We did not report any NGL sales volumes in TY23.

Licensing and royalties

The leases for our US Gulf of Mexico assets are standard U.S. federal offshore Outer Continental Shelf oil and gas leases awarded by the U.S. Bureau of Ocean Energy Management or BOEM. These leases are subject to regulation by, among others, the U.S. Bureau of Safety and Environmental Enforcement and the Office of Natural Resources Revenue. We pay royalties in the amount of 12.50% of the value of production to the Office of Natural Resources Revenue.[35] Under certain conditions, we are able to obtain royalty relief in the form of temporary waivers of royalty payments. Royalty relief may be available if market prices are low or if the US government wants to incentivize production in frontier areas or deeper depth.

We present the revenue we earn from our USA segment on a net of royalties basis. Because royalties can be taken in kind in the United States, our USA segment revenues are our actual sales less any royalties levied, resulting in lower sales volumes and revenue than if we reported on the same basis as our Brazilian segment. See "Management's discussion and analysis of financial condition and results of operations—Key factors affecting our results—Government royalties" and "Regulatory overview—Regulatory overview—US Gulf of Mexico."

In addition, we pay royalties in connection with specific leases to third parties under agreements with prior interest holders. For example, certain limited zones of block MC 502, on which the Who Dat field is partly located, are subject to a 5% overriding royalty stemming from a farm-out agreement with Eni Petroleum US LLC.

Who Dat reserves

The following tables set forth our NRI of 1P, 2P and 3P reserve estimates for the Who Dat assets as of December 31, 2023.

We engage independent experts as required to assist with the integrity of our reserves and contingent resources estimates. We engaged independent expert Netherland, Sewell & Associates, Inc., or NSAI, to deliver an independent reserve report for the Dome Patrol and Who Dat oil and gas fields, as of December 31, 2023. A summary of this report has been included in this offering memorandum in Annex A. We have relied upon NSAI's independent reserve report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

35 Source: Wood Mackenzie Consulting, Karoon Energy, Brazil and US Gulf of Mexico Offshore Market Assessment, April 2024, Section 4.5 US GoM Fiscal Summary. See Annex B.

We have used a conversion factor of 6 mcf equaling 1 boe to convert from gas to oil equivalent. In accordance with the US Gulf of Mexico fiscal scheme, our NRI shows our working interest net of royalties charged by the American Office of Natural Resources Revenue and third-party royalties. See also "Cautionary note regarding reserves and contingent resources," "Reserves and contingent resources" and "—Licensing and royalties."

Reserves

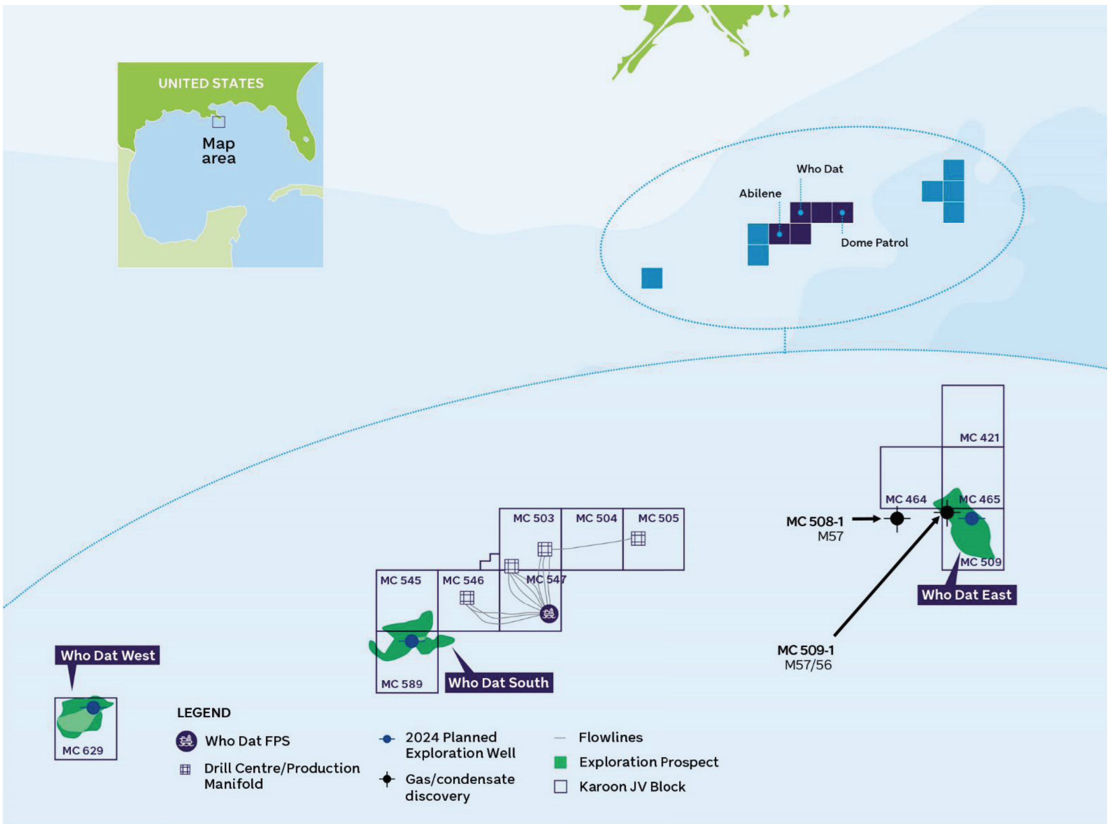
	As of December 31, 2023		
	1P	**2P**	**3P**
Who Dat, Dome Patrol and Abilene			
Oil (MMbbl)	13.9	19.5	29.1
Gas (bcf)	37.7	61.5	79.8
NGL (MMbbl)	0.7	1.2	1.5
Oil equivalent (MMboe)	**20.9**	**31.0**	**43.9**

Development and exploration assets

As part of our acquisition of the Who Dat assets, we also acquired varying interests in adjacent acreage including the Who Dat East (40% interest), Who Dat West (35% interest) and Who Dat South (30% interest) exploration and appraisal opportunities.

All three of the Who Dat East, Who Dat West, and Who Dat South opportunities are within tie-back distance of the Who Dat floating production system. We estimate that drilling costs for these prospects will be approximately US$60 million per well on a gross, dry-hole basis and that our share of capital costs for all three wells will amount to approximately US$100-120 million. As part of our acquisition, we agreed to up to US$39.2 million in additional payments relating to the exploration of Who Dat East and Who Dat West. All drilling opportunities in the Who Dat prospects are amplitude-supported and calibrated by nearby wells and proven reservoirs. This approach has led to high drilling success rates in the past.

The following map show the location of Who Dat West, Who Dat South and Who Dat East.



Who Dat East

Who Dat East lies 27 kilometers east of the Who Dat floating production system facility. The joint venture intends to drill an appraisal well at Who Dat East starting in late April 2024. We also expect an exploration well to be drilled at Who Dat South in the second half of 2024, and subject to approval by the joint venture partners, a second exploration well to be drilled at Who Dat West, also during the second half of 2024. All three of these opportunities are within tie-back distance of the Who Dat floating production system. We have estimated 2C contingent resources of 5.4 MMboe on a NRI basis for our share of Who Dat East. Within the Who Dat East permit, there is also a deeper Cretaceous gas target for which seismic studies are ongoing.

The following tables sets forth our NRI of our 2C contingent resource estimates for Who Dat East as of December 31, 2023. See also "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

Contingent resources

	As of December 31, 2023
	2C
Who Dat East	
Oil (MMbbl)	1.9
Gas (bcf)	20.5
NGL (MMbbl)	0.0
Oil equivalent (MMboe)	**5.4**

Who Dat West

Who Dat South lies 31 kilometers west of the Who Dat field. Subject to joint venture approvals, we expect an exploration well to be drilled at Who Dat West in the second half of 2024, which will target multiple Middle Miocene stacked reservoirs.

Who Dat South

Who Dat South lies 11 kilometers south-west of the Who Dat field. Subject to joint venture approvals, we expect an exploration well to be drilled at Who Dat South in the second half of 2024.

Joint venture partners

Our joint venture partners for the Who Dat and Dome Patrol oil and gas fields are LLOG (45%) and Westlawn (25%). Our joint venture partners for the Abilene field are LLOG (approximately 21%), Westlawn (approximately 12%) and China National Offshore Oil Corporation (approximately 50%). All of our Who Dat assets are operated by LLOG, a private independent US operator with extensive technical expertise and experience.

We have entered into several conventional US Gulf of Mexico deepwater joint operating agreements with our joint venture partners in connection with our Who Dat assets. These operating agreements contain usual terms and conditions relating to the commitment of expenditure and the undertaking of joint operations by the operator on behalf of joint venture participants. Usual terms regarding the election to participate in certain joint operations such as exploration or development are included, generally with the ability for specific joint venture participants being afforded the opportunity to opt out of certain operations or developments at certain times. Each joint venture participant is entitled to receive and market its share of production.

Production and sales summary

The following tables summarize our historical production and sales data for FY21, FY22, FY23, HY23 and TY23, and *pro forma* production and sales data on a net revenue interest basis for FY23 and TY23 as if we had acquired our share in the Who Dat assets on July 1, 2022. See "Unaudited pro forma combined financial information" and "Selected unaudited pro forma combined financial information."

	Historical					Pro Forma[2]	
	For the six months ended December 31,		For the twelve months ended June 30,			For the twelve months ended June 30,	For the six months ended December 31,
	2022	2023[1]	2021	2022	2023	2023	2023
Production (MMboe)..	3.37	5.47	3.14	4.64	7.04	9.78	6.83
Sales volume (MMboe).....................	3.41	5.07	2.90	4.54	7.06	9.76	6.40
Weighted average realized price (net of selling expense) (US$/boe)...................	87.86	81.51	59.00	84.74	80.20	75.09	77.11

Notes:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

(2) Includes our share in the Who Dat assets on a NRI basis as if we had acquired our share in the Who Dat assets on July 1, 2022.

The following tables summarize our historical production volumes by asset and by product for FY21, FY22, FY23, HY23 and TY23.

Production volume by assets

	For the six months ended December 31,		For the twelve months ended June 30,		
	2022	2023	2021	2022	2023
Brazil					
Baúna (MMbbl)	3.37	5.38	3.14	4.64	7.04
United States					
Who Dat[1] (MMboe)	–	0.09	–	–	–
Total (MMboe)	**3.37**	**5.47**	**3.14**	**4.64**	**7.04**

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Production volume by product

	For the six months ended December 31,		For the twelve months ended June 30,		
	2022	2023[1]	2021	2022	2023
Oil (MMbbl)..........................	3.37	5.44	3.14	4.64	7.04
Gas (MMboe)	–	0.03	–	–	–
Total (MMboe)	**3.37**	**5.47**	**3.14**	**4.64**	**7.04**

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

The following tables summarize our sales volume by asset and by product for FY21, FY22, FY23, HY23 and TY23.

Sales volume by asset

	For the six months ended December 31,		For the twelve months ended June 30,		
	2022	2023	2021	2022	2023
Brazil					
Baúna (MMbbl)	3.41	4.98	2.90	4.54	7.06
United States					
Who Dat[1] (MMboe)	–	0.09	–	–	–
Total (MMboe)	**3.41**	**5.07**	**2.90**	**4.54**	**7.06**

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Sales volume by product

	For the six months ended December 31,		For the twelve months ended June 30,		
	2022	2023[1]	2021	2022	2023
Oil (MMbbl)	3.41	5.04	2.90	4.54	7.06
Gas (MMboe)	–	0.03	–	–	–
Total (MMboe)	**3.41**	**5.07**	**2.90**	**4.54**	**7.06**

Note:

(1) Includes our share in the Who Dat assets on a NRI basis for the period from December 21, 2023 to December 31, 2023, following our acquisition.

Reserves and contingent resources

The following table summarizes our net oil and gas 1P, 2P and 3P reserves estimates as of December 31, 2023. For more information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

	As of December 31, 2023[(1)]		
	1P	**2P**	**3P**
		(MMboe)	
Brazil			
Baúna[(2)]	37.1	46.5	55.8
United States			
Who Dat[(3)]	20.9	31.0	43.9
Total	**58.0**	**77.5**	**99.7**

Notes:

(1) We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserve reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's independent reserve report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material. See "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

(2) Includes developed reserves from the producing Baúna, Piracaba and Patola oil fields. We had no undeveloped 1P, 2P or 3P reserves as of December 31, 2023 in Baúna.

(3) Includes our share of developed and undeveloped reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields.

The following tables summarize our net oil and gas 2C contingent resources estimates as of December 31, 2023. For more information on our reserves and resources, see "Cautionary note regarding reserves and contingent resources" and "Reserves and contingent resources."

	As of December 31, 2023
	2C
	(MMboe)
Brazil	
Baúna[(1)]	10.9
Neon	60.1
Goia	27.0
United States	
Who Dat East[(2)]	5.4
Total (MMboe)	**103.4**

Notes:

(1) Includes Contingent Resources from the Baúna, Piracaba and Patola oil fields.

(2) Includes our share of Contingent Resources in the Who Dat East oil and gas field on a NRI basis.

Our concession agreements and leases

The table below shows our interests in petroleum tenements as of the date of this offering memorandum.

Field	Exploration permit/block	Operator	Interest held	Concession term/status	Termination events
Santos Basin, Brazil					
Baúna	Concession BM-S-40	Karoon	100%	Exploration and production rights granted until 2039.	All our concession agreements in Brazil are subject to termination by ANP under certain circumstances. See "—Termination events of our concession agreements in Brazil" below.
Neon	Block S-M-1037	Karoon	100%	Exploration and production rights granted until 2045.	
Goiá	Block S-M-1101	Karoon	100%	Exploration and production rights granted until 2045.	
Clorita	Block S-M-1537	Karoon	100%	Exploration rights granted until 2025.[1]	
Block S-M-1356	Block S-M-1356	Karoon	100%	We successfully participated in government bid round in December 2023 and expect the concession contract to be signed within the second quarter of 2024.[2]	
Block S-M-1482	Block S-M-1482	Karoon	100%	We successfully participated in government bid round in December 2023 and expect the concession contract to be signed within the second quarter of 2024.[2]	

Field	Exploration permit/block	Operator	Interest held	Concession term/status	Termination events
Mississippi Canyon, Gulf of Mexico, United States					
Who Dat	MC 502	LLOG	30%	Held by production Certain limited zones subject to a 5% overriding royalty interest by Eni Petroleum US LLC	All leases in the Gulf of Mexico are subject to termination by BOEM (i) if the holder of interest fails to comply with any provision of the OCSLA, the lease, or applicable regulations; (ii) if BOEM determines the lease was obtained by fraud or misrepresentation; (iii) if after a hearing, it is determined continued activity will probably cause serious harm or damage to life, property, any mineral, national security or defense, or the marine, coastal, or human environment; (iv) any time after lease operations have been suspended or temporarily prohibited by the Department of Interior continuously for a period of 5 years; or (v) if the holder of an interest in a lease fails to provide a bond, or alternative type of security instrument acceptable to BOEM. Any lease will also terminate automatically pursuant to the terms of the lease if there is no production, drilling or other qualifying operations being conducted.
	MC 503			Held by production Subject to overriding royalty interests by several third parties, including Black Streak in the amount of 0.6%	
	MC W/2 504			Subject to expiration by June 30, 2024 unless drilling operations or production in paying quantities commences. The joint venture currently has no plans to drill or apply for unitization of this field.	
	MC E/2 546			Held by production	
	MC E/2 547			Held by production	
Dome Patrol	MC E/2 504	LLOG	30%	Subject to expiration by June 30, 2024 unless drilling operations or production in paying quantities commences. The joint venture currently has no plans to drill or apply for unitization of this field.	
	MC E/2 505			Held by production	
Abilene	MC W/2 546	LLOG		Held by production	
Who Dat South	MC 545	LLOG	30%	Subject to expiration by September 30, 2024 unless drilling operations or production in paying quantities commences.	

Field	Exploration permit/block	Operator	Interest held	Concession term/status	Termination events
	MC 589			Subject to expiration by July 31, 2024 unless drilling operations or production in paying quantities commences.	
Who Dat West..........	MC 629	LLOG	35%	Subject to expiration by June 30, 2024 unless drilling operations or production in paying quantities commences.	
Who Dat East...........	MC 509	LLOG	40%	Subject to expiration by June 30, 2025 unless drilling operations or production in paying quantities commences. LLOG has applied for unitization of the Who Dat East field.(3) Following a successful unitization application, our joint venture application intends to drill an exploration well on MC 509, which will satisfy the requirements to extend the leases of the unitized Who Dat East field.	
	MC 421			Subject to expiration by May 31, 2024 unless drilling operations or production in paying quantities commences. Subject to a 2% overriding royalty interest by Hess Corporation LLOG has applied for unitization of the Who Dat East field.(3)	
	MC 464			Subject to expiration by May 31, 2024 unless drilling operations or production in paying quantities commences. Subject to a 2% overriding royalty interest by Hess Corporation LLOG has applied for unitization of the Who Dat East field.(3)	

Field	Exploration permit/block	Operator	Interest held	Concession term/status	Termination events
	MC 465			Subject to expiration by May 31, 2024 unless drilling operations or production in paying quantities commences. Subject to a 2% overriding royalty interest by Hess Corporation LLOG has applied for unitization of the Who Dat East field.(3)	
	MC 508			LLOG has negotiated a lease exchange agreement with Chevron, leaseholder of MC 508, under which Chevron would transfer lease MC 508 to LLOG, which will then transfer the relevant interests to the joint venture partners. In consideration for the transfer Chevron would be granted exploration and production rights below 27,600ft in MC 508, MC 421 and MC 464. The agreement remains subject to approval, including from the joint venture partners. LLOG has applied for unitization of the Who Dat East field, including MC 508.(3)	

Notes:

(1) By January 2025, we can either (i) request an extension of the exploration phase, (ii) return the block to ANP or (iii) declare the commerciality of the block and enter in the development phase.

(2) We expect to be granted seven years of exploration rights after which we can either (i) request an extension of the exploration phase, (ii) return the block to ANP or (iii) declare the commerciality of the block and enter in the development phase.

(3) Unitization is a process by which leases or parts thereof, are combined and operated as a single unit, with production or operations from one tract in the unit being treated as production or operations from every tract included in the unit.

Termination events of our concession agreements in Brazil

The following table sets out the circumstances our concession contracts can be terminated for each field in Brazil.

Field	Termination events
Baúna	Our concession contract may be terminated: (i) in case of non-compliance with any of our obligations which is not corrected within 90 days of notice; (ii) if we are declared bankrupt, insolvent or file for bankruptcy; (iii) if by the end of the exploration term there is no discovery in the concession area; (iv) in the case of a severe unforeseeable event or force majeure; or (v) by us at any time during the production phase by means of a written notification to ANP.
Neon and Goiá	Our concession contract may be terminated: (i) in case of non-compliance with any of our obligations which is not corrected within 90 days of notice; (ii) if we are declared bankrupt, insolvent or file for bankruptcy; (iii) if by the end of the exploration term there is no discovery in the concession area; (iv) in the case of a severe unforeseeable event or force majeure; or (v) by us at any time during the production phase by means of a written notification to ANP; (vi) if the proposed licensing necessary for exploration activities receives a definitive rejection from the competent environmental agencies; or (vii) in case of failure to execute any required production individualization agreement.
Clorita	Our concession contract may be terminated: (i) upon expiry of its term; (ii) if we have not complied with the minimum exploration program at the end of the exploration phase; (iii) if no commercial discovery was made at the end of the exploration phase; (iv) if we return the concession area in its entirety; (v) if a development plan has not been submitted within a deadline specified by ANP; (vi) if ANP fails to approve the development plan; (vii) in case of a refusal to sign the production individualization agreement in whole or in part, following a decision by ANP; (viii) in the case of a decree of bankruptcy or failure by the competent court to approve our application for judicial reorganization; (ix) by mutual agreement between the parties at any time, without prejudice to the fulfilment of the obligations in the concession contract; (x) during the production phase, by us through providing notice to ANP at least 180 days prior to the intended date of termination; (xi) in case of non-compliance with any of our obligations which is not corrected within 90 days of notice; (xii) in case of a judicial or extrajudicial reorganization, unless we have submitted an approved reorganization plan which demonstrates to ANP the economic and financial capacity to fully comply with all our contractual and regulatory obligations; (xiii) in the case of a severe unforeseeable event or force majeure; (xiv) if the proposed licensing necessary for exploration activities receives a definitive rejection from the competent environmental agencies; or (xv) if the concession contract is suspended for licensing purposes for a term greater than 5 years.

Field	Termination events
Block S-M-1356 and Block S-M-1482.....	Our concession contract may be terminated: (i) upon expiry of its term; (ii) if we have not complied with the minimum exploration program at the end of the exploration phase; (iii) if no commercial discovery was made at the end of the exploration phase; (iv) if we return the concession area in its entirety; (v) if we exercise our right to withdraw during the exploration phase, provided that we have complied with the minimum exploration program or have paid a corresponding compensation amount; (vi) if a development plan has not been submitted within a deadline specified by ANP; (vii) if ANP fails to approve the development plan; (viii) in case of a refusal to sign the production individualization agreement in whole or in part, following a decision by ANP; (ix) in case of failure to renew financial guarantees within 30 days prior to their expiration date; (x) in the case of a decree of bankruptcy or failure by the competent court to approve our application for judicial reorganization; (xi) by mutual agreement between the parties at any time, without prejudice to the fulfilment of the obligations in the concession contract; (xii) during the production phase, by us through providing notice to ANP at least 180 days prior to the intended date of termination; (xiii) in case of non-compliance with any of our obligations which is not corrected within 90 days of notice; (xiv) in case of a judicial or extrajudicial reorganization, unless we have submitted an approved reorganization plan which demonstrates to ANP the economic and financial capacity to fully comply with all contractual and regulatory obligations; (xv) in case of a partial termination of the concession contract in case we do not provide adequate financial guarantees for the minimum exploratory program, provided that the respective areas are not in development; (xvi) in the case of a severe unforeseeable event or force majeure; (xvii) if the proposed licensing necessary for exploration activities receives a definitive rejection from the competent environmental agencies; or (xviii) if the concession contract is suspended for licensing purposes for a term greater than 5 years.

Sustainability

Sustainability is a core element of our business strategy and underpins our vision to deliver energy through safe, reliable and responsible operations. We link our executive remuneration to specific outcomes within the health, safety and security and climate pillars, reflecting our core ESG priorities.

Climate

While we continue to grow as a producer and build on our existing operations, we are aiming to optimize our processes so that our emissions are, wherever practical, reduced in terms of emissions intensity. Our carbon management action plan, which we first adopted in 2021, is designed to deliver short term and longer-term climate-related outcomes. For the Baúna Project, we have a continued objective of being carbon neutral and a target to be net zero (Scope 1 and 2) by 2035.

CARBON NEUTRAL FY 2023 SCOPE 1 AND 2 GHG EMISSIONS		
Baúna Project Expected to remain Carbon Neutral* ✔	Carbon Neutral on new assets within five years of purchase* ✔	Internal carbon pricing for new investment decisions ✔
NET ZERO BY 2035 SCOPE 1 AND 2 GHG EMISSIONS		

* Scope 1 and 2 GHG emissions

We report our sustainability metrics with reference to the voluntary 'IFRS Sustainability Disclosure Standards', developed by the International Sustainability Standards Board and are also guided by the Australian National Greenhouse and Energy Reporting Act for our carbon accounting.

Our carbon management action plan

Our carbon management action plan describes how we want to achieve our targets:

- *Avoid and reduce:* We were able to avoid emissions of 2,850tCO_2e in FY22 and 5,293tCO_2e in FY23 through operational improvements including the installation of a mooring buoy in FY22 and optimizing support vessel scheduling. As part of our emissions reduction program for 2024, we are undertaking a review of the energy generation systems at Baúna.

- *Assess investments in high quality offsets:* We have a 9-year agreement in place with SWST to purchase over 480,000 externally verified emission reduction certificates, which we expect will offset approximately 60% or our forecast Baúna emissions. During TY23, we signed an exclusive 5-year agreement with Carbonext, securing over 340,000 externally verified carbon units with an additional certification under the 'Climate, Community and Biodiversity Standards.' These relate to the 'Hiwi REDD+' project, located in Bujari, Northern Brazil and are registered with global certifier of voluntary carbon offsets VERRA.

- *Purchase of additional offsets if required:* We continue to investigate opportunities to acquire high quality carbon offsets as we work towards developing our own carbon projects. Until we acquire a portfolio of offset generating assets we will need to rely on offset purchases from external providers.

- *Internal carbon pricing:* We are applying an internal carbon price ranging from approximately US$45/t in 2023 to more than US$130/t in 2050 to take emissions into account in our internal decision making whenever we consider new investments. We also include actual abatement costs of projects in our budgets to assist with the purchase of appropriate amounts of carbon credits.

Our climate performance

Scope 1 emissions are direct emissions from sources that we own or control. This includes emissions from stationary combustion (for example in generator turbines onboard the floating production, storage and offloading facility), mobile combustion (for example in supply vessels and fleet cars), fugitive emissions (for example from general leaks) and process emissions (for example from flaring).

Scope 2 emissions are indirect emissions from the generation of purchased energy in our operations. Scope 2 emissions account for less than 0.1% of our total Scope 1 and 2 emissions. Our Australian office participates in the Australian GreenPower program since 2021, ensuring that our electricity use is matched with power from renewable electricity sources such as solar, wind and biomass.

The following tables show our historical Scope 1 and Scope 2 emissions data for TY23, FY23 and FY22.

	TY23	FY23	FY22
Scope 1 emissions (tCO_2e)	**59,319**	**142,025**	**82,805**
Operational control(1)	58,866	142,025	82,805
Equity share(2)	453	–	–
Scope 2 emissions (tCO_2e)	**28**	**49**	**65**
Operational control(1)	28	49	65
Equity share(2)	–	–	–
Scope 1 and 2 emissions (tCO_2e)	**59,347**	**142,074**	**82,870**
Operational control(1)	58,894	142,074	82,870
Equity share(2)	453	–	–
Emissions Intensity ($KgCO_2e$/bbl)	10.9	20.2	17.9

Notes:

(1) This data includes emissions relating to the Baúna asset and other operations under our control.

(2) This data includes emissions relating to our equity share in our US Gulf of Mexico assets following our acquisition on December 22, 2023. It does not include drilling.

The Baúna workover program, the Patola development, and drilling of two control wells at the Neon oil field significantly increased our GHG emissions during FY23. The rig operations also more than doubled our production rates prior to commencing natural decline, which reduced our Scope 1 and 2 emissions intensity. Our annualized GHG emissions decreased slightly during TY23, partially due to the completion of drilling operations in the previous period.

Our Scope 1 and Scope 2 emissions intensity was above 20.0 $kgCO_2e$/bbl during the year ended December 31, 2023 due to drill and construction activities. Due to operational efficiencies and increased production volumes, our Scope 1 and Scope 2 emissions intensity dropped to 10.9 $kgCO_2e$/bbl during TY23. Our emissions are reported in terms of tonnes carbon dioxide equivalent and primarily comprise carbon dioxide, methane and nitrous oxide.

Approximately 40% of the associated gas produced at the Baúna floating production, storage and offloading facility is used to power the floating production, storage and offloading facility with most of the remainder reinjected and only a small amount flared for process safety. Recognizing the damaging effects of methane, we aim to minimize flaring in our operations.

Our emissions outlook

Following the workover and drilling campaign, oil production at the Baúna project increased materially. It has now resumed a gradual decline, consistent with reservoir models. This is expected to increase the Company's emissions intensity over the next year. In addition, the acquisition of our US Gulf of Mexico assets during TY23 has increased our scale and diversification and will also increase our absolute GHG emissions portfolio. We continue to progress studies and projects to reduce our emissions intensity and the absolute emissions of our respective operations and implement these, where practical.

Environment

We are committed to conducting safe, reliable, and responsible operations while minimizing our environmental impact and protecting biodiversity. We are continuously monitoring a range of parameters to ensure compliance with applicable environmental regulations and license requirements. Our key monitoring areas are water and plankton; sediment and benthic habitat; produced water, and oil spills.

Our oil spill response plan encompasses a systematic approach that includes preventive measures, preparedness, and response actions, such as regular maintenance of equipment, safety protocols, and training programs for crew members. We conduct regular drills and maintain the availability of support vessels on standby during operations. Consistent with industry practice, we enter into clubbing arrangements with other industry participants to assist in oil spill response. Additionally, we established a standing agreement with a well control services company to address major incidents efficiently.

We employ the 'Spilltrack System' to monitor and forecast oil drift at sea. Leveraging the Spilltrack System emergency response buoys, ocean drifters, and 'Expendable Current Profiler' probes, we have access to oil dispersion modelling, trajectory monitoring of oil slicks on the ocean surface, and current measurements along the water column. These advanced tools provided integrated support to response vessels, enabling the best estimation of oil slick directions and optimizing our response efforts to reduce environmental impacts.

We are also subject to decommissioning requirements in connection with our operations. For example, we are required to provide assurance of and a detailed decommissioning plan five years prior to the planned end of our production at Baúna.

The table below shows our environmental incidents for TY23, HY23, FY23, FY22 and FY21, including incidents related to contractors undertaking work for us. It does not include data from our partly-owned and non-operated assets in the US Gulf of Mexico, which we acquired during TY23.

	HY23	TY23(1)	FY21	FY22	FY23
Number of minor spills (to sea)(2)	0	1	2	0	2
Number of non-minor spills	0	0	0	0	0
Number of incidents in offloading operations	0	0	0	0	0

Notes:

(1) This data does not include incidents for our US Gulf of Mexico assets, which we acquired on December 22, 2023.

(2) Minor spills are spills having a volume of less than 0.16 m^3 as defined by ANP.

Supply chain

We engage major suppliers through long-term charter and services contracts to undertake our Baúna production operations, and on short term contracts when undertaking other major activities. We conduct specific risk assessments ahead of operational activities and major investment decisions. We are working closely with our major suppliers, aiming to ensure worker health and safety is given first priority in relation to our operations. Our personnel also visit manufacturing facilities to inspect the working conditions and practices and we maintain ongoing engagement with our major suppliers.

We have distributed questionnaires to all our major suppliers globally to identify vulnerabilities to modern slavery risks in our supply chain entities since 2021. During TY23, we completed a modern slavery risk assessment for suppliers representing 99.5% of our annual spend during FY23. None of them were identified as high-risk. We have submitted our third Modern Slavery Statement in February 2024 in accordance with the obligations under the Australian Modern Slavery Act 2018 and also undertake screening in relation to anti-bribery, fraud and corruption and health, safety, security and environmental matters.

Community engagement

In connection with our Baúna concession agreements, we have mandatory commitments to undertake projects to protect biodiversity and ecologically sensitive areas associated with our operational activities and to support community social initiatives.

Examples of our mandatory projects are the Social Communication Project and Project RUMO, which were both required by federal licensing overseen by the Brazilian Institute of Environmental and Renewable Natural Resources or IBAMA. The Social Communication Project consists of an ongoing information and consultation campaign that helps keep our staff, contractors, local communities, and regulatory authorities informed about our operations. Project RUMO was an environmental education project where we developed information about the use of the maritime zone and the coastal space of the Itajaí-Açu river estuary between November 2020 and February 2023.

We began to develop our voluntary investment program in Brazil during FY22 and have aligned our approach to the UN Sustainable Development Goals 4, 8 and 17, which focus on education and employment. Our projects during the year ended December 31, 2023 included support of 'Pro-Crep', a project that provides work opportunities and steady income to families in socially vulnerable situations and 'Liter of Light', a project with the objective of providing street lightning for the Alto da Serra Cafundá Quilombola Community, located in the city of Rio Claro-RJ.

Employees and industrial relations

We employed 115 full time and part-time employees as of December 31, 2023. In addition, on average, there were 83 employees of our contractor Altera & Ocyan working on the floating production, storage and offloading facility during FY23. The table below outlines where our employees are based as of December 31, 2023.

	Location		
	Australia	**Brazil**	**United States**
Office	27	86	2
Operational sites[1]	0	2	0

Note:

(1) Includes our personnel on board of the floating production, storage and offloading facility.

Industrial relations

We employ the vast majority of our employee workforce under individual common law contracts between the company and the employee. We believe we have experienced a harmonious and productive relationship with our employees with no significant industrial action or stoppages occurring across any projects over the past five years. As of the date of this offering memorandum, none of our employee workforce are members of any labor unions.

All suppliers and employees have access to grievance mechanisms through a whistleblower reporting service that facilitates both named and anonymous reporting. Employees and stakeholders can raise concerns confidentially via phone or email to our external reporting services (available in Portuguese and English), who will then pass the details of the report to our general counsel and chairman of the audit and risk committee.

Diversity

As of December 31, 2023, we had 115 permanent employees, of which 42% were women, exceeding our target of 30%. At the same date, 17% of our senior leaders, which we define as the three reporting levels below our chief executive officer, were women. Our participation rate of women on the board currently stands at 17%.

The following table shows the historical and target percentage of female participation across our business.

	As of December 31,			**As of June 30,**		
	2022	**2023**	**2025[1]**	**2021**	**2022**	**2023**
Board	17	17	30	17	17	14
Senior leadership[2]	17	17	30	26	17	11
Group	43	42	30	50	46	41

Notes:

(1) Target.

(2) The term "senior leadership" is defined for the purposes of the diversity analysis by reference to our internal organizational structure and encompasses the three reporting levels below our chief executive officer.

Health and safety

We prioritize the health and safety of our employees. The following table shows our safety performance for our operations, covering all personnel working on our operations, for FY21, FY22, FY23, HY23 and TY23. It does not include data from our partly-owned and non-operated assets in the US Gulf of Mexico, which we acquired during TY23.

Safety Performance[1]	**FY21**	**FY22**	**FY23**	**HY23**	**TY23**
Fatalities	0	0	0	0	0
High potential incidents[2]	1	2	1	0	0
Lost time injuries[3]	1	4	1	1	0
Medical treatment cases[4]	2	0	2	2	0
Restricted work cases[5]	1	0	1	1	0
Work exposure hours[6]	625,9281	1,028,000	1,948,000	1,026,000	468,664
Total recordable injury rate (per 200,000 hours)[7]	0.64	0.77	0.41	n/a	0.0
Lost time injury rate[8]	0.32	0.77	0.10	n/a	0.0
Tier 1 or 2 process safety events[9]	n/a	0	0	0	0

Notes:

(1) This table does not include data from our partly-owned and non-operated assets in the US Gulf of Mexico, which we acquired during TY23.

(2) High potential incidents are defined as any incident or near miss incident that could, in other circumstances, have realistically resulted in one or more fatalities.

(3) A lost-time injury is a work-related injury or illness that results in a person's disability, or time lost from work of one shift or more.

(4) Medical treatment cases are defined as cases that are not severe enough to be reported as lost work day cases or restricted work day cases but are more severe than requiring simple first aid treatment.

(5) Restricted work cases are defined as any work-related injury other than a fatality or lost work day case which results in a person being unfit for full performance of the regular job on any day after the occupational injury.

(6) Work exposure hours are total standard or actual hours worked by all employees and contractors during a specific period.

(7) A statistical measure of health and safety performance, calculated by the number of recordable incidents per 200,000 hours worked.

(8) A statistical measure of health and safety performance, calculated by the number of lost time injuries per 200,000 hours worked.

(9) Tier 1 and Tier 2 Process safety events are defined by API RP754, American Petroleum Institute Guide to Reporting Process Safety Events and refer to varying degrees of an unplanned or uncontrolled release of any material, including non-toxic and non-flammable materials (e.g. steam, hot water, nitrogen, compressed CO_2, or compressed air).

During FY23, we experienced a material increase in exposure hours due to the implementation of the Baúna Project workover campaign, the Patola development drilling and control well drilling at Neon. Despite increased exposure hours, we only experienced a total of four reportable safety incidents and injuries during FY23. The most significant of these was a lost time injury incident, constituting of a finger injury which required surgery. The worker subsequently returned to his duties without permanent injury.

Our US Gulf of Mexico assets are operated by our joint venture partner LLOG. According to data published by the Bureau of Safety and Environmental Enforcement in the United States, measured by total recordable injury rate per 200,000 hours, LLOG has historically had an above-industry safety record for the Who Dat assets. During the year ended December 31, 2023, the total recordable injury rate (per 200,000 hours) for the Who Dat assets stood at 0.0. At the end of March 2024, the Who Dat floating production system facility went through more than 4,550 days since its last reportable safety incident and more than 4,250 days since its last recordable safety incident.

Since taking operatorship of the producing Baúna oil field in November 2020, we have been working closely with the Baúna floating production, storage and offloading facility operator, Altera & Ocyan, to ensure our commitment to health, safety and environment is imbedded throughout the Baúna operations. This includes linking remuneration to safety performance.

Our operating management system encompasses policies, guidelines, and procedures and is regularly reviewed and updated. We also work with regulatory agencies such as the ANP and the Brazilian Institute of Environment and Renewable Natural Resources to conduct external audits, assessing our compliance with specific regulatory criteria.

We conduct hazard and operability studies at the activity level and risk assessments at the project and business levels. Our assessments are regularly updated, placing a strong emphasis on safety. We do not proceed with any activity until safety risks are reduced to as low as reasonably practicable and an acceptable level. We encourage our employees and contractors to halt work in unsafe situations or when relevant health, safety, or environmental controls are inadequate. We employ hazard reporting via our own and contractors' 'Safe Card' systems. Our crisis management team, based at our head office in Melbourne, Australia, maintains oversight of incident responses, and takes responsibility for controlling group-wide business continuity and strategic decision-making. Regular training drills are in place so that personnel are well prepared for emergency events, with IBAMA observing these drills at least once a year in Brazil. Key operational responses, including offshore medical evacuation and oil spill response, are thoroughly tested through full deployment drills. We monitor the Baúna facility's safety performance via regular reporting and audits, and our onboard company representatives.

We also place a heavy emphasis on safety standards as part of our contracting process and review the safety performance of our contractors. We will only contract with parties that have sufficient safety standards integrated into their operating practices.

Information Technology

As an oil and gas producer and operator of critical infrastructure, we aim to take a proactive approach to cyber risk management. We conduct regular risk assessments, vulnerability testing, and incident response planning and strive to identify and mitigate potential threats before cyber risks materialize. We employ a global infrastructure architecture in our operations to ensure group wide visibility of our operations and consistent event monitoring. Our cyber security framework complies with the American National Institute of Standards and Technology maturity level 3 as well as with the Australian Privacy Act and relevant Brazilian laws.

We employ a "one Karoon" strategy, providing a single controlled environment across a global domain program that spans our operations in Australia, Brazil and the United States. Our IT architecture provides a secure environment for business applications across our business and our layered approach allows, where required, for local area network infrastructure applications to run locally, within the protection of the group-wide network.

We also employ IT systems and security tools to increase our productivity and efficiency as well as reduce our vulnerability. For example, Altera & Ocyan use "SpillTrack System" on board of the *Cidade de Itajaí*. SpillTrack is a web-based tool to help us monitor and forecast oil drift at sea, which assists us in modelling of oil dispersion, monitoring of oil slicks and water current measurements. See "—Environment" above for further details.

Insurance

We believe we maintain prudent levels of insurance coverage in accordance with industry practices in the jurisdictions in which we operate, taking into account the size and scope of our operations and our risk exposure. The insurance we carry includes loss of production insurance that applies to both our Brazilian and USA assets. We typically review on an annual basis the appropriateness of our insurance coverage and amend our policies to any changes in circumstance, being either external market conditions or a change in our business operations. We maintain an insurance program for our participating interest across all operations.

Our insurance does not cover all of the risks and potential losses we face, including because insurance is not available for certain risks, we consider the premiums too high relative to the risk or we elect to self-insure by setting aside amounts of cash or liquid securities that we deem sufficient to cover the occurrence of any such risks. See "Risk factors—Risks relating to our industry and operations—Our insurance arrangements may be inadequate to cover losses arising from our operations" for further details.

Legal proceedings

From time to time, we are involved in disputes with counterparties, joint venture partners, regulators, employees and others in the ordinary course of our business. Given the nature of the oil and gas business, the contractual arrangements we make with joint venture partners, vendors of businesses we acquire, customers of our products and suppliers of equipment and services are often complex and can give rise to disputes due to the complexity of the agreements and the occurrence of circumstances that were not anticipated by the parties. We may also have disagreements with regulators including oil and gas industry regulators and tax authorities about the interpretation of laws and regulations or the application of laws to complex facts. These disputes may involve dispute resolution processes including commercial arbitration and litigation. A number of our agreements contain arbitration clauses that require us to keep arbitration proceedings confidential unless we are required by law to disclose them.

In addition, there continues to be public debate on the environmental and social impact of oil and gas activities. See "Risk factors—Risks relating to our industry and operations—Increasing attention to ESG matters may adversely impact our business and strategic objectives."

We do not expect that the resolution of any of the disputes or debates in which we are currently engaged will have a materially adverse effect on our operations or financial results.

RESERVES AND CONTINGENT RESOURCES

We estimate our petroleum reserves and contingent resources in accordance with the procedures and classifications set out in the Society of Petroleum Engineers (SPE) Petroleum Resource Management System (PRMS) 2018 (PRMS 2018). Australian companies listed on the ASX are required to report their petroleum reserve and contingent resource estimates in accordance with PRMS 2018.

Under PRMS 2018, petroleum reserves are defined as "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied."

Reserves are subdivided into three categories in accordance with the level of certainty associated with the estimates: "proved", "probable" and "possible."

Proved reserves (1P) 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."

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."

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."

We also present in this offering memorandum our "2C" contingent resources. Contingent resources are "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies." Contingent resources may include "projects for which there are currently no viable markets, where commercial recovery is dependent upon technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not approved, or where regulator or social acceptance issues may exist." Quantities reported as "2C" contingent resources represent our "best estimate" of our contingent resources. When probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the 2C estimate. We may reclassify our contingent resources into reserves if we are able to establish their commercial viability, which includes the requirement that we evidence a firm intention to proceed with development within a reasonable time-frame.

Readers should apply particular caution to our 3P reserve estimates and our 2C contingent resource estimates. 3P reserves include estimated quantities of hydrocarbons the extraction of which we do not consider probable. Our contingent resources are estimates of hydrocarbon quantities that are not recoverable under current conditions and may never become recoverable. We would not be permitted to disclose our 3P reserves or 2C contingent resources in an SEC registration statement.

Our definitions of proved reserves and probable reserves (under PRMS 2018) vary in certain respects from the definitions of those terms used by the SEC and set out Rule 4-10 of Regulation S-X under the Securities Act. For example, Rule 4-10 requires reserves to be estimated based on existing economic conditions, including prices calculated as the unweighted arithmetic average of the closing price on the first day of each month in the preceding 12-month period at the end of the period covered by the reserves report, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. We estimate reserves based on contract prices, where applicable, and forecast prices for uncontracted volumes and to estimate contract prices for market-linked contract pricing mechanisms.

The way we assess our share of reserves and contingent resources from the Who Dat assets is different from how we calculate reserves and contingent resources at our Brazilian assets. We report our share of reserves and contingent resources from the Who Dat assets net of royalties owed to the American Office of Natural Resources Revenue (amounting to 12.50%) and any other third parties. This approach is consistent with the SEC reporting system, which considers royalties to be a share of the petroleum reserves to which the license owner does not have title, so that reserves are reported "net" of royalty percentages. This is due to royalties being taken "in-kind" in the United States. This reporting basis is known as net revenue interest, or NRI. Our system of reporting at Baúna treats these royalties as a tax on the revenue generated by the production and sale of hydrocarbons, so that Baúna reserves and contingent resources are generally reported without excluding any percentage for royalties. This reporting basis is generally known as net working interest, or NWI. If the royalties payable under each relevant regime were treated as arising under an "in-kind" royalty regulatory regime, this would decrease our reportable reserves. While the NRI basis of reporting will produce a lower reserves and contingent resources figure when compared to the NWI basis for the same oil or gas field, this will not change our net share of profits from production from that field.

Members of our Reserves Committee consider and assess all proposed changes and additions to our reserves and contingent resources. In doing so, they consider advice and contributions from subject matter experts and external consultants. Our estimates are based on, and fairly represent, information and supporting documents prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator. Unless noted otherwise, all references to petroleum reserves and contingent resources in this offering memorandum represent our net share. The reference points for our petroleum reserves calculations are at the sales point situated at the relevant production facility.

Our reserves and contingent resources estimates and the recoverability of the quantities of petroleum we have identified as reserves and contingent resources are subject to risk factors associated with the oil and gas industry, which include price fluctuations, actual demand, currency fluctuations, geotechnical factors, drilling and production results, gas commercialization, development progress, operating results, engineering estimates, loss of market, industry competition, environmental risks, physical risks, legislative, fiscal and regulatory developments, economic and financial markets conditions in various countries, approvals and cost estimates. For further discussion of the risks and uncertainties inherent in reserves and contingent resource estimations, see "Risk factors—Risks relating to our industry and operations—Our oil and gas reserve and resource estimates are subject to inherent technical and geological uncertainty and may be revised downwards as a result of lower commodity prices or changed regulation that may result in previously booked reserves no longer being commercially recoverable."

We engage independent experts as required to assist with the integrity of our reserves and contingent resources estimates. We engaged independent experts AGR Energy Services AS, or AGR, and Netherland, Sewell & Associates, Inc., or NSAI, to deliver independent reserves reports for Baúna and for the Dome Patrol and Who Dat oil and gas fields, respectively, as of December 31, 2023. Summaries of those reports have been included in this offering memorandum in Annex A. As of December 31, 2023, AGR's estimate of our 2P reserves in Baúna was approximately 2.5% lower than our estimate of 2P reserves. We have relied upon NSAI's independent reserves report in preparing our estimates of our share of reserves and contingent resources from the Who Dat assets, and any differences between our estimates and the estimates presented by NSAI relate to differences in oil price forecasts. As of December 31, 2023, NSAI's estimate of our share of 2P reserves from the Who Dat assets was approximately 0.6% lower than our estimate of 2P reserves. We believe that the differences between our reserves estimates and those of AGR and NSAI reflect differences in reasonable professional judgment in interpreting data and applying assumptions and are not material.

Reserves and contingent resources estimation using the deterministic method involves an assessment based on discrete estimates made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty. The probabilistic method involves using known geoscience, engineering and economic data to generate a continuous range of estimates and their associated probabilities. We have prepared our petroleum reserves and contingent resources at Baúna using a combination of deterministic and probabilistic methods. AGR used a combination of deterministic and probabilistic methods in estimating our our petroleum reserves and contingent resources at Baúna. NSAI used deterministic methods in estimating our share of petroleum reserves and contingent resources from the Who Dat assets.

The following table sets forth our 1P, 2P and 3P petroleum reserves as of December 31, 2023.

	As of December 31, 2023		
	1P	**2P**	**3P**
		(MMboe)	
Brazil			
Baúna[(1)]	37.1	46.5	55.8
Gulf of Mexico			
Who Dat[(2)]	20.9	31.0	43.9
Total	**58.0**	**77.5**	**99.7**

Notes:

(1) Includes reserves from the producing Baúna, Piracaba and Patola oil fields presented on a NWI basis.

(2) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

The following table sets forth our 2C petroleum contingent resources as of December 31, 2023.

	As of December 31, 2023
	2C
	(MMboe)
Brazil	
Baúna[(1)]	10.9
Neon[(2)]	60.1
Goia[(3)]	27.0
Gulf of Mexico	
Who Dat East[(4)]	5.4
Total	**103.4**

Notes:

(1) Includes contingent resources from the Baúna, Piracaba and Patola oil fields presented on a NWI basis. These figures reflect the amount of contingent resources we estimate would be recoverable following a potential FPSO life extension.

(2) These contingent resources are assessed within the development unclarified subclass and have not been subject to a commerciality determination. We allocate a contingent resource to this subclass when "project activities are under evaluation and where justification as a commercial development is unknown based on available information." While we report the recoverable resource for the whole field in this contingent resource figure, any finalized development plan may not recover all of these resources. Presented on a NWI basis.

(3) Presented on a NWI basis.

(4) Includes our share of contingent resources in the Who Dat East oil and gas field presented on a NRI basis.

The following tables sets forth our developed, undeveloped and total petroleum reserves as of December 31, 2023. Undeveloped reserves are reserves that we expect to recover: (1) from new wells on undrilled acreage; (2) from deepening existing wells to a different reservoir; or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

	As of December 31, 2023		
	1P reserves		
	Developed	Undeveloped	Total
		(MMboe)	
Brazil			
Baúna[1]	37.1	–	37.1
Gulf of Mexico			
Who Dat[2]	12.3	8.6	20.9
Total	**49.4**	**8.6**	**58.0**

Notes:

(1) Includes reserves from the producing Baúna, Piracaba and Patola oil fields presented on a NWI basis.

(2) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

	As of December 31, 2023		
	2P reserves		
	Developed	Undeveloped	Total
		(MMboe)	
Brazil			
Baúna[1]	46.5	–	46.5
Gulf of Mexico			
Who Dat[2]	17.4	13.6	31.0
Total	**63.9**	**13.6**	**77.5**

Notes:

(1) Includes reserves from the producing Baúna, Piracaba and Patola oil fields presented on a NWI basis.

(2) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

	As of December 31, 2023		
	3P reserves		
	Developed	Undeveloped	Total
		(MMboe)	
Brazil			
Baúna[1]	55.8	–	55.8
Gulf of Mexico			
Who Dat[2]	24.2	19.7	43.9
Total	**80.0**	**19.7**	**99.7**

Notes:

(1) Includes reserves from the producing Baúna, Piracaba and Patola oil fields presented on a NWI basis.

(2) Includes our share of reserves from the producing Who Dat, Dome Patrol and Abilene oil and gas fields presented on a NRI basis.

The following table sets out the annual changes in our 1P, 2P and 3P reserves from June 30, 2021 to December 31, 2023. We round our reserves figures to the nearest single decimal point, and some totals in the tables below may not add due to rounding. Items that round to zero are represented by the number 0, while items that are actually zero are represented with a dash "–."

	1P reserves reconciliation			2P reserves reconciliation			3P reserves reconciliation		
	Oil & condensate	NGL	Natural gas	Oil & condensate	NGL	Natural gas	Oil & condensate	NGL	Natural gas
	(MMbbl)		(Bcf)	(MMbbl)		(Bcf)	(MMbbl)		(Bcf)
Reserves (as of June 30, 2021)	**41.1**	**–**	**–**	**49.4**	**–**	**–**	**66.1**	**–**	**–**
Production	(4.6)	–	–	(4.6)	–	–	(4.6)	–	–
Reserves (as of June 30, 2022)	**36.5**	**–**	**–**	**44.8**	**–**	**–**	**61.5**	**–**	**–**
Production	(7.0)	–	–	(7.0)	–	–	(7.0)	–	–
Revisions	10.3	–	–	14.0	–	–	6.8	–	–
Reserves (as of June 30, 2023)	**39.8**	**–**	**–**	**51.8**	**–**	**–**	**61.3**	**–**	**–**
Production	(5.5)	(0.0)	(0.2)	(5.5)	0.0	(0.2)	(5.5)	0.0	(0.2)
Revisions	2.6	–	–	0.1	–	–	(0.1)	–	–
Acquisitions	14.0	0.7	37.9	19.6	1.2	61.7	29.2	1.5	80.0
Reserves (as of December 31, 2023)	**50.9**	**0.7**	**37.7**	**66.0**	**1.2**	**61.5**	**84.9**	**1.5**	**79.8**

The following table sets out the annual changes in our 2C contingent resources from June 30, 2021 to December 31, 2023. We round our contingent resources figures to the nearest single decimal point, and some totals in the tables below may not add due to rounding. Items that round to zero are represented by the number 0, while items that are actually zero are represented with a dash "–."

	2C contingent resources		
	Oil & Condensate	NGL	Natural gas
	(MMbbl)		(Bcf)
Contingent resources (as of June 30, 2021)	**86.2**	**–**	**–**
Contingent resources (as of June 30, 2022)	**86.2**	**–**	**–**
Removal of SPS-57 hook-up	(4.2)	–	–
Baúna Life Extension Project	11.1	–	–
Neon post control well drilling	5.1	–	–
Contingent resources (as of June 30, 2023)	**98.2**	**–**	**–**
Acquisitions	1.9	0.0	20.5
Revisions	(0.2)	–	–
Contingent resources (as of December 31, 2023)	99.9	0.0	20.5

Regulatory overview – Brazil

Brazilian Federal Constitution

Pursuant to the Brazilian Federal Constitution, the federal government holds the monopoly on the prospecting, exploitation, development and production, refinery, import and transportation of oil and natural gas, and of other fluid hydrocarbons. The Brazilian Federal Constitution previously prohibited the assignment or concession of any kind of activity involving oil or natural gas exploitation to private companies.

On November 10, 1995, the Brazilian Congress approved Constitutional Amendment No. 9, amending the Brazilian Federal Constitution to permit the federal government to contract with state-owned or private companies the prospecting, refinery, import, transportation, exploration and production of oil and natural gas (*i.e.*, upstream activities) and the refining of derivatives and oil and natural gas (*i.e.*, midstream and downstream activities), subject to applicable law.

Brazilian Oil Law

Federal Law No. 9,478, dated August 6, 1997, or the Brazilian Oil Law, sets forth the rules and principles for contracting upstream, midstream and downstream activities in Brazil. Among other measures, the Brazilian Oil Law:

- reaffirmed the federal government's monopoly on deposits of oil, natural gas and other fluid hydrocarbons and provided that the exploitation and production of these hydrocarbons is regulated and supervised by the federal government;

- created: (i) the CNPE or Brazilian National Council for Energy Policy, a body subordinated to the President of Brazil and responsible for establishing the public policies related to the energy industry; and (ii) ANP, a regulatory agency bound to the Ministry of Mines and Energy, and responsible for regulating upstream, midstream and downstream activities;

- repealed Federal Law No. 2,004/53, pursuant to which the federal government could only exercise its monopoly through Petrobras and its subsidiaries;

- set forth the main terms and conditions applicable to concession agreements pursuant to which the federal government may contract with state-owned or private companies that intend to operate in the refining, development, and production of hydrocarbons; and

- ratified the activities carried out by Petrobras prior to its enactment, granting Petrobras, irrespective of any bidding process, the exclusive right to explore the fields where Petrobras had been producing and the areas in relation to which it could show evidence of previous investments and work.

CNPE

The National Energy Policy Council, or CNPE, created by the Brazilian Oil Law, is a body subordinated to the President of Brazil and led by the Minister of Mines and Energy. CNPE is responsible for establishing the Brazilian energy policies and oil and natural gas production policies and setting forth the guidelines for the bidding processes for the concession of exploitation rights, pursuant to the Brazilian Oil Law.

ANP

The Brazilian Oil Law established the National Agency of Petroleum, Natural Gas, and Biofuels or ANP, a Brazilian federal governmental agency, which is supervised by the Ministry of Mines and Energy. ANP is responsible for regulating the Brazilian oil, natural gas, and biofuels industry. One of ANP's main goals is to create a competitive environment for activities related to oil and natural gas in Brazil, thus resulting in lower prices and better-quality services for consumers, including ensuring fuel supply. Its main responsibilities include: (i) promoting and requiring compliance with Brazilian oil, natural gas and biofuels industry regulations; (ii) carrying out bidding processes for the concession of exploration, development and production rights related to oil, natural gas and biofuels, and entering into, on behalf of the federal government, the relevant concession agreements; (iii) authorizing the transportation, import, export, refining and processing of oil, oil products, natural gas and biofuels; and (iv) overseeing the economic activities of the oil, natural gas and biofuels industries, in each case in accordance with Brazilian interests.

Concession bids

Since 2010, three oil and gas rights regimes have coexisted in Brazil: concession, production sharing, and onerous transfer of rights. In the concession contracts model, the concessionaire takes on all risks and investments in exploration and production. After payment of taxes and government takes, hydrocarbons produced become the exclusive property of the concessionaire, to use or sell at its discretion. In the production sharing contracts model, the private contractor undertakes the exploration and production activities at its own expense and risk. The Brazilian Federal Government's interests in the production sharing regime are represented by Petrobras, which is a party to such contracts and has the right of preference to be operator of the blocks. In the event of a commercial discovery, the contractor receives, as reimbursement, the production volume corresponding to its incurred exploration expenses, also known as cost oil. The government's take of commercial oil discoveries is provided to the Brazilian Federal Government, which distributes it to states and municipalities. The onerous transfer of rights contracts represent areas that Petrobras has exclusivity over until the areas' aggregate production reaches 5 billion barrels of oil and gas. After such milestone, Petrobras has the right to decide which areas to keep and which areas to relinquish to the ANP, which will offer the relevant E&P rights in bidding processes. Karoon's Brazilian blocks were each awarded in concession bids.

To attract private investment, the Brazilian Oil Law established the main terms and conditions to be applied by the federal government when granting concessions for the exploration, development and production of hydrocarbons.

ANP represents the federal government and is responsible for granting concession agreements for the exploration, development and production of oil and natural gas in the Brazilian onshore and offshore sedimentary basins by means of a transparent and competitive bidding process. The only exception to the mandatory bidding process requirement was Round Zero, when concession agreements were granted directly to Petrobras under the onerous transfer of rights regime, dismissing the bidding process, in relation to the exploration blocks where Petrobras had already performed activities and/or made investments before the date of enactment of the Brazilian Oil Law. This direct concession was an acknowledgment of the activities already carried out in these areas by Petrobras, as the sole operator of the former monopoly held by the federal government, and a ratification of its vested rights. From 1999 to 2023, ANP conducted 17 bidding rounds for exploration blocks under the concession regime, and six bidding rounds under the production sharing regime. In addition, ANP has a process of permanently offering areas through accepting bids on new concession blocks in any onshore or offshore basins, with marginal accumulations as well as offering concession fields returned or in the process of being returned to ANP. If determined by the CNPE, the ANP may also include fields or blocks under the production sharing regime (i.e., located in the pre-salt area or in strategic areas) in a permanent offer. As of the date of this offering memorandum, ANP conducted two cycles of permanent offers for blocks under the production sharing regime and is currently conducting the fourth cycle of permanent offers for concession areas.

The definition of the blocks subject to concession is based on geological and geophysical data that indicate the presence of hydrocarbons. In addition, to minimize environmental impacts, ANP, IBAMA and regional environmental agencies make a prior analysis of the areas to be offered.

After that analysis, ANP publishes the requirements for the environmental license regarding the offered blocks, allowing future concessionaires to assess the environmental aspects related to their areas of interest.

The first step of the qualification process to participate in a permanent offer concession bid is the submission of a set of mandatory documents, which constitute the statement of interest. Companies that submit their statement of interest are required to pay a participation fee, which may vary according to the basin where the blocks are located. After payment of the participation fee, they receive a data package with technical information and geological summaries regarding the area.

After this initial stage, qualified companies that decide to continue in the bidding process must undergo a second eligibility review, in which ANP confirms the technical, legal and financial capabilities of these bidding companies in order to present an offer and prior to executing the concession agreement.

Technical qualification. Each company's technical qualification includes its experience in the exploration and production of hydrocarbons. Companies that wish to qualify as operators must submit a technical summary with information that proves their operating capacity. Companies that wish to qualify as non-operators may only participate in a bidding round as members of a consortium led by a qualified operator.

Legal qualification. In order to obtain legal qualification, a company must submit to ANP certain corporate documentation, including its constituent documents and a description of its corporate structure. A foreign company must submit documentary evidence that it was legally formed according to the laws of its country of origin and, if it wins the bidding process, the foreign company must agree to incorporate a company with headquarters and management located in Brazil.

Financial qualification. A company's financial qualification is subject to a minimum shareholders' equity that varies based on each qualifying level. Companies with shareholders' equity below the amount required by ANP cannot participate in the bidding process, except as a member of a consortium, *i.e.*, as a non-operator. The financial qualification is also based on the company's audited financial statements, its bank references and/or other financial documents.

The companies that succeed in this process are then considered eligible to participate in the bidding round and submit an offer. Companies must individually meet all qualification requirements to participate in ANP's bidding rounds and once qualified may present their offers, either alone or as part of a consortium. In the case of a consortium, ANP requires the appointment of a consortium leader to act as the operator responsible for the consortium and the operations, and the other consortium members, even if not operators, are jointly and severally liable for the obligations undertaken under the accession agreement.

ANP analyzes the proposals submitted by the companies and selects the most advantageous offer according to the objective criteria established in the bid notice. Each proposal is scored based on the weighted sum of points given in regard to each evaluation factor. In the last bidding rounds, ANP used a formula that included the following evaluation factors: (i) the signing bonus, accounting for 80% of the score; and (ii) the ANP Minimum Exploratory Program, accounting for 20% of the score. The winners of the bidding round are subject to a second eligibility review, in which the ANP will assess whether or not they meet the minimum technical, legal and financial qualification requirements of the relevant areas at stake.

Once it fulfils these requirements, a company qualifies to enter into a concession agreement with the federal government for those areas for which a winning bid was submitted.

Government participation

Pursuant to the Brazilian Federal Constitution, Brazilian Oil Law and other ANP regulations, concessionaires must pay the following amounts to the federal government:

- signing bonus;
- area occupation or retention fee;
- special participation fee; and
- royalties.

The minimum amount of the signing bonus is established in the bid notice and the final amount is based on the amount of the winning proposal. The signing bonus must be paid upon execution of the concession agreement with ANP.

The occupation or retention fee for the areas under concession is established in the bid notice and must be paid annually. For the calculation of this fee, ANP takes into account, among other factors, the location and the size of the awarded block and the sedimentary basin and its geological features. Decree No. 2,705/98 provides for both minimum and maximum amounts of the occupation or retention fees, in accordance with the stage of the awarded block.

For fields with high production or profitability, a special participation fee may be payable. When payable, this fee is calculated through progressive rates that vary according to the location, lifetime of the field, and production volumes, pursuant to applicable regulations. The special participation fee related to each field is payable on a quarterly basis from the date the high production or profit occurred and is calculated based on the quarterly net revenue of each field, *less*: (i) royalties paid; (ii) investments made in exploitation; (iii) incurred operating costs; and (iv) depreciation and applicable taxes.

ANP is also responsible for determining monthly royalties related to production. Royalties are calculated at a rate ranging from 5% to 10% of the gross revenue from production. For the determination of the royalty percentage applicable to a specific block under concession, ANP takes into account the block's geological risks and the expected production, among other factors.

Pursuant to the Brazilian Oil Law, onshore concessionaires must pay the landowner a special participation fee, ranging from 0.5% to 1.0% of the gross revenue from production of each well located on the owner's land.

On September 21, 2018, ANP enacted ANP Resolution No. 749/2018, which regulates the procedure for granting reduction of royalties as an incentive to incremental production in mature fields.

Article 9 of ANP Resolution No. 749/2018 states that mature fields of small production will have royalties calculated at a rate of five percent (5%) on incremental production. On the other hand, for mature fields of high production, according to the Article 10, the royalties will be calculated by applying regressive rates corresponding to seven and a half percent (7.5%) and five percent (5%), according to the percentage of increase achieved.

Mature fields are classified by Article 2, item III, of the Resolution No. 749/2018 as oil or natural gas field with a history of effective production, carried out from definitive production facilities, greater than or equal to 25 years, or whose accumulated production corresponds to at least seventy percent (70%) of the volume expected to be produced, considering the proved reserves.

"Incremental production" represents the positive difference between the volumes of oil and natural gas actually produced in a given month and the monthly production volumes forecast for this month corresponding to the forecast calculated according to the reference production curve of the field, as stated in the Article 2, item V, of the Resolution No. 749/2018. Baúna field, the sole producing asset in our Brazilian portfolio is a mature field and benefits from this incentive.

On September 28, 2021, ANP published Resolution No. 853/2021, reducing the royalties rate related to fields granted to small and medium-sized companies. The size classification of a company is based on the annual average production of the concession holder, as an independent company or corporate group, pursuant to ANP Resolution No. 32/2014, as follows: (i) companies with annual average production of less than 1,000 boepd are classified as small companies; and (ii) companies with annual average production of less than 10,000 boepd are classified as medium-sized companies.

Following ANP's enactment of resolutions granting a reduction of the royalties rates to: (i) to incremental production in mature fields; and (ii) to small and medium-sized companies, on August 12, 2022, CNPE's published Resolution No. 5/2022, providing for measures to stimulate the development and production of hydrocarbon accumulations in economically viable marginal fields. The oil and gas fields and deposits with economic potential, as well as those corresponding to marginal fields are defined by ANP Resolution No. 877/2022 depending on their production rate, API grade, level of contaminants and reserves reports.

Concession agreements

ANP is responsible for granting concession agreements for the exploration, development and production of oil and natural gas reserves to market players, independently or in joint ventures with other ANP-qualified companies, by means of a transparent and competitive bidding process.

In addition to public biddings, companies in the oil and gas industry may also acquire their participating interest in a specific exploration block or producing field under concessions contracts by means of farm in and farm out (i.e., sale and purchase) agreements. These agreements set forth the percentage of equity interest in the block/field being assigned and are subject to ANP's approval, which is granted upon fulfillment of the technical economic and legal requirements by the assignee, in accordance with the terms and conditions of ANP Resolution No. 785/2019.

The concession agreements executed with ANP set forth the rights and responsibilities of the winning bidders regarding certain exploration blocks, providing for the exploration phase and the production phase. The exploration phase may last from two to eight years and the production phase may last up to 27 years from the date of declaration of commercial feasibility. The production phase may be extended for additional 27 years upon the concessionaire's requires and ANP's approval.

Since the fifth concession bidding round, the concession agreements for hydrocarbon exploration and production started to provide for two exploration periods, and the term of each period is provided for in the applicable concession agreement. In practice, each bidding round will have its own rule.

Each exploration period is subject to an ANP Minimum Exploratory Program, in which the concessionaire agrees to comply with certain obligations, terms and conditions for the development of its activities. The concessionaire must comply with the ANP Minimum Exploratory Program before advancing to the next exploration or production phase.

In the first exploration period, the concessionaire's activities usually consist of geophysical and geochemical surveys and seismic reprocessing related to the concession area. If the concessionaire decides to move on to the second exploration period and has complied with all the ANP Minimum Exploratory Program obligations, the exploration will move on to the drilling of an exploration well. The concession agreements list the activities to be performed during the exploration phase. Moreover, concessionaires must present a financial collateral (letter of credit, insurance bond or oil and gas pledge) to secure the ANP Minimum Exploratory Program, as a condition precedent for the execution of the concession agreement. In the event of noncompliance with the ANP Minimum Exploratory Program, the ANP may foreclose the submitted collateral, without prejudice, and impose sanctions set forth in the applicable legislation.

The exploration phase ends upon submission of a declaration of commercial feasibility, which states that the concessionaire believes it is possible to carry out production in the relevant area. The production phase begins upon delivery of the declaration of commercial feasibility to ANP. The concessionaire then implements the necessary infrastructure and starts producing oil or gas. If the concessionaire decides that the area is not commercially viable, the concessionaire returns it to ANP upon notice and does not initiate the production phase.

Pursuant to the Brazilian Oil Law, the concession agreement must include: (i) the definition of the concession block; (ii) the term of duration and main conditions for exploration and production activities; (iii) the rules and conditions for the partial return and vacation of the concession areas; (iv) the guarantees to be offered by the concessionaire to assure that the concession agreement, including the investments required in each phase, will be complied with; (v) penalties in case the concessionaire fails to comply with the agreement; (vi) the procedures for the assignment of the agreement; (vii) the rules and conditions for the return and full vacancy of the concession areas, with the removal of the equipment and facilities, and reversal of assets; (viii) the procedures to monitor and inspect the exploration, development and production activities, and to audit the agreement; (ix) the obligation of the concessionaire to provide to ANP reports, data and information related to the developed activities; (x) the procedures related to the transfer of the concession agreement, pursuant to Article 29 of the Brazilian Oil Law; (xi) the rules on the resolution of disputes related to the agreement and its performance, including settlement and international arbitration; (xii) the events of termination of the agreement; and (xiii) the penalties applicable in the event of non-compliance by the concessionaire of its contractual obligations.

Concessionaires have the following rights, among others: (i) the exclusive right to the exploration, development and production in the concession area; (ii) ownership of the produced hydrocarbons; (iii) the right to sell the produced hydrocarbons; and (iv) the right to export the hydrocarbons, subject to compliance with obligations regarding domestic supply in the event of declaration of a state of emergency.

The main obligations of a concessionaire include: (i) bearing all costs and risks related to the exploration, development and production of hydrocarbons, including any liability for environmental damages; (ii) complying with the requirements regarding the acquisition of assets and services from domestic suppliers (local content); (iii) complying with the requirements regarding performance under the ANP Minimum Exploratory Program referred to in the winning proposal; (iv) oil reserve conservation; (v) delivering to ANP periodic reports, data and information; (vi) paying government participation fees; (vii) paying the costs related to the deactivation of facilities, pursuant to Brazilian legislation and best practices of the Brazilian oil industry and (viii) following the provisions of the annual work programs.

For additional information on our concession agreements, see "Business—Our concession agreements and leases."

Consortiums and Joint Operating Agreements

In order to minimize the exploration risks and allow for a more diversified portfolio, a number of oil and natural gas companies join consortiums to present proposals. In this case, before the bidding process, companies must execute an agreement for the submission of a joint proposal, which sets forth a timetable for the joint survey of the relevant area and each member's equity interest in the project, among other conditions. In general, the parties share the costs related to the concession area proportionally to their equity interest in the area. Pursuant to Brazilian law, consortium members are jointly and severally liable and, since the consortium does not have its own legal personality, each consortium member must keep separate and independent accounting records.

Once the bidding round ends, before or after the execution of the concession agreement with ANP, consortium members often enter into a joint operating agreement to establish the responsibilities and investments required for the exploration and production of the bid block. These agreements are usually based on a standard agreement form prepared by the Association of International Energy Negotiators, or AIEN. In general, consortia are managed by an operating committee, which is the highest authority of the consortium, responsible for supervising and setting forth guidelines for joint operations.

Bidding Rounds

The most recent and already completed concession bidding rounds include: (i) the 17th bidding round, in 2020, with the offer of 92 blocks in the Campos and Potiguar Sedimentary Basins, as well as in the offshore sedimentary basins of *Pelotas* and *Santos*, totaling an area of 53,900 km^2; and (ii) the 16th bidding round, in 2019, with the offer of 36 blocks in the Campos Sedimentary Basin and in the offshore sedimentary basins of *Pernambuco-Paraíba*, *Jacuípe*, *Camamu-Almada*, and *Santos*, totaling an area of 29,300 km^2.

The last production sharing bidding round was the sixth production sharing bidding round, in 2019, with the offer of the following blocks: *Aram*, *Bumerangue*, *Cruzeiro do Sul*, *Sudoeste de Sagitário* and *Norte de Brava*.

In addition, CNPE Resolution No. 17, dated June 8, 2017, approved the adoption of a permanent offer process, which consists of the continuous offer of returned fields or fields in the process of being returned, and exploration blocks that were not awarded in previous rounds or were returned to the ANP. ANP holds a session for the submission of offers upon receipt of at least one declaration including an offer guarantee for each area of interest. ANP holds this session within 90 days from the date of receipt of the declaration.

The fourth cycle of the permanent offer under concession regime took place in December 2023, with the award of 192 exploratory blocks located in the Potiguar, Espírito Santo, Recôncavo Sedimentary Basins, as well as the *Pelotas, Santos, Paraná, Tucano, Amazonas*, and *Sergipe-Alagoas* sedimentary basins, totaling an area of 47,143.86 km^2. In addition, one marginal accumulation area located in the onshore *Amazonas* sedimentary basin was awarded, totaling an area of 57.29 km^2. Our wholly owned subsidiary Karoon Petróleo e Gas Ltda or KPG, successfully bided for two deepwater exploration blocks located in the Santos basin. KPG is expected to execute the respective concession agreements for these areas within the second quarter of 2024.

Two cycles of the permanent offer under production sharing regime have been carried out by ANP. The second cycle of the permanent offer under production sharing regime took place in December 2023, with the award of one exploratory block located in the *Santos* sedimentary basin, totaling an area of 47,143.86 km^2.

Decommissioning

The decommissioning of oil and natural gas exploration and production systems consists of the permanent interruption of activities associated with the operation of the facilities. It is a legal requirement that the decommissioning process be carried out when the life cycle of the production system ends, and it is an integral part of the oil and gas industry's production cycle.

Once the need for decommissioning has been confirmed, the concessionaire company plans and carries out the activities in accordance with prevailing regulations, including environmental legislation, following strict safety standards and analyzing project alternatives based on multidisciplinary criteria (environmental, technical, safety, social and economic), which allows it to select the decommissioning alternative that generates the least impact. This analysis also considers studies and guidelines on best practices in the oil and gas industry worldwide. As a result of the analysis and prior to initiating the decommissioning of its facilities, the concessionaire shall prepare and submit a decommissioning plan, which must contain all necessary projects, studies and guarantees that would sustain the intended decommissioning work. ANP will then review the presented plan and may authorize the operator of the facilities to start decommissioning the facilities.

The decommissioning process includes various activities, such as disposing of the platform and subsea system and abandoning wells, carried out in accordance with the decommissioning plan approved by the regulatory bodies and in compliance with the applicable legal requirements.

As of the date of this offering memorandum, KPG as the concessionaire has not initiated any decommissioning activities in any of our exploration and production areas in Brazil.

Decommissioning Guarantee

Pursuant to ANP Resolution No. 854 dated September 27, 2021, ANP requests the submission of a financial guarantee to assure decommissioning activities for all concession areas under production phase.

In this context, the concessionaires must engage in discussions about a decommissioning guarantee with the Production and Development Department at ANP under the terms of the ANP Resolution No. 854/2021, which sets out the criteria, rules, and procedures for providing a financial guarantee that ensures financial resources for the decommissioning of production facilities in oil and natural gas fields. The guidelines of the ANP Resolution No. 854/2021 must be observed by concessionaires so that the financial conditions offered for the abandonment activities of oil and natural gas fields are accepted by ANP.

The types of guarantees accepted by ANP are: (i) letter of credit; (ii) guarantee insurance; (iii) pledge of oil and natural gas; (iv) corporate guarantee; or (v) provision fund. For exploration and production agreements not undergoing any assignment processes and that were in force on the date of publication of Resolution No. 854/2021, as amended ANP Resolution No. 925/2023, parties had until October 2, 2023 to comply with the terms of such resolution and implement the necessary adjustments to the guarantees already presented. The acceptance of each financial guarantee is subject to the discretion of ANP, which may order the replacement of the adopted guarantee at any time, whenever a technical study shows that the presented guarantee is insufficient or inadequate.

We currently satisfy the requirements for a decommissioning guarantee, through the presentation of a surety bond in the amount of US$98.2 million and a US$1,000 deposit into a provision fund. The scope of the decommissioning guarantee encompasses all fields included in the BM-S-40 license, which is our only producing asset in Brazil. We are not required to provide decommissioning guarantees with our other non-producing assets in Brazil.

The decommissioning guarantee obligation is reviewed annually in accordance with the published guidelines and adjusted annually for the required guaranteed amount. The revised decommissioning obligation is typically communicated in April of each year. As of the date of this offering memorandum, our guarantee obligation remains subject to finalization with ANP.

A failure to provide the guarantee for the decommissioning in assignment processes pending with the ANP will result in the assignment not being completed, as the guarantee is a requirement set forth in ANP Resolution No. 854/2021. The failure to renew the decommissioning guarantees may cause their foreclosure by ANP, pursuant to ANP Resolution No. 854/21, and subject the concessionaire/contractor to the penalties set forth in Law No. 9,847/1999 for noncompliance with requirements set forth in applicable law and in ANP Resolutions.

Local Content

Local content refers to the contractual obligation arising from a concession contract to meet specific percentage thresholds for sourcing goods, services, and personnel locally. Law No. 12,351/2010 defines local content as the proportion between the amount of goods produced and services performed in Brazil for the performance of an agreement and the total amount of goods and services employed for the same purpose.

In April, 2017, the Brazilian Government announced a significant reduction of the local content requirements for the then current bid rounds. This reduction contributed to the success of Brazil Rounds 14 and 15 under the concession regime, and Pre-Salt Bid Rounds 2, 3, 4 and 5 under the production sharing regime, all held in 2017 and 2018.

In order to address the local content requirements of concession contracts that were granted in previous bid rounds, the ANP published, in April 2018, Resolution No. 726/2018, which regulated amendments to the local content clauses of the concession contracts executed through the Brazil Round 13. It also established rules regarding exemptions (waivers), adjustments of percentages and transfer of local content "excess" in respect of concession contracts awarded under the Brazil Rounds 7 through 13.

ANP Resolution No. 726/2018 permits concessionaires to either: (i) amend concession contracts, in order reduce their local content percentage commitments (in which case they would waive the right to request local content waivers from ANP); or (ii) not amend the concession contracts and maintain the right to request waivers of local content commitments from ANP.

In addition, ANP Resolution 848/2021 established procedures to be followed by concessionaires to execute a conduct adjustment agreement for the replacement of previously assessed local content fines by ANP with new investments in local content in different phases of the concession contract or other concession contracts.

In connection with ANP Resolution 848/2021, we entered into a conduct adjustment agreement that provides that we are not liable for any and all liabilities or local content fines arising in connection with non-compliance of local content requirements incurred prior to the assignment of Blocks S-M-1288 and S-M-1289 (which form part of Baúna), to us, during the exploration phase of Baúna.

ANP further regulated the obligation to evidence compliance with local content requirements by establishing, among other matters: (i) the criteria and audit procedures for the activity of certification of local content (ANP Resolution No. 19/2013); (ii) applicable requirements for local contents reports to be provided by concessionaires to ANP (ANP Resolution No. 871/2022) to prove compliance with the relevant requirements; and (iii) rules for accreditation by a local content certification entity (ANP Resolution No. 963/2023).

Pre-Salt and Strategic Areas

"Pre-salt" refers to a series of hydrocarbon discoveries in the rock layer under a thick layer of salt. These discoveries were in an area approximately 300 to 350 kilometers off the coast of São Paulo, Espírito Santo and Rio de Janeiro states. The discovery of oil and natural gas in the pre-salt area in Brazil led to a new regulatory framework regarding these and other strategic areas. New laws were enacted, including: (i) Law No. 12,276/10, which authorized the federal government to assign the survey and production of oil, natural gas and other fluid hydrocarbons in pre-salt areas that are not under concession granted to Petrobras, representing up to 5.0 billion barrels of oil, which occurred in September 2010; (ii) Law No. 12,351/10, which established the production sharing regime for the pre-salt and other strategic areas; (iii) Law No. 12,304/10, which authorized the formation of the state-owned company Pré-Sal Petróleo S.A., or PPSA, whose corporate purpose is the management of the production sharing agreements executed by the Ministry of Mines and Energy; and (iv) Law No. 13,679/2018, which grants PPSA the right to directly carry out the sale of oil, natural gas and other fluid hydrocarbons of the federal government. Under the production sharing regime, the Brazilian government awards agreements to private companies for the exploration and production of oil and natural gas, pursuant to which these companies are entitled to a share in the production.

Conversely, under the concession regime, the concessionaire is the owner of the entire production, subject to the payment of the government's share, pursuant to the Brazilian Oil Law and the relevant concession agreements. Under the production sharing agreement, the contractor performs the exploration, assessment, development and production activities at its own risk. In the event of a commercial discovery, the contractor receives, as reimbursement, the production volume corresponding to its incurred exploration expenses also known as cost oil. In addition to cost oil, the contractor receives the production volumes corresponding to payable royalties and profit oil or excess oil, in the proportion, conditions and terms set forth in the agreement. The structure proposed by the Brazilian government also includes these traditional concepts of cost oil, whose limits are determined in each agreement, and profit oil. In bidding processes, agreements are awarded to the companies that offer the highest percentage of profit oil to the government, above the percentage limit set forth in the bidding process. In a production sharing partnership, a state-owned company is specially formed to act on behalf of the government.

Pursuant to Law No. 13,365/16, which amended Law No. 12,351/10, or the Sharing Regime Law, Petrobras is no longer required to act as operator in all the blocks under the production sharing regime. Pursuant to the amended Sharing Regime Law, CNPE will grant Petrobras the right of first refusal to operate the blocks to be awarded.

The partnership between the Brazilian government and the consortium, which includes Petrobras and private partners, is managed by an operating board. The Brazilian government elects 50% of the members of the operating board, including the chairman, who has the casting vote and veto rights. The operating board is responsible for all important management and operating decisions regarding the partnership, including decisions on investments and production segregation arrangements, or production unitization.

The first production sharing bidding round occurred in 2013, with the offer of the *Libra* oil field, in the Campos Sedimentary Basin. Even though eleven companies confirmed their interest in the offer, only one consortium, comprising Petrobras, Shell, Total, CNPC and CNOOC, submitted an offer, thus winning the bid. CNPE authorized the seventh and eighth production sharing bidding rounds, the 18th concession bidding round, and the aforementioned permanent concession offer.

More recently, CNPE Resolution No. 26/2021 was published, allowing for the first time, bidding rounds of blocks under the production sharing regime through the permanent offer model. Until then, the permanent offer only covered areas to be offered under the concession regime. In December 2023, ANP carried out the fourth bidding round of the permanent concession offer. A total of 192 exploratory blocks were auctioned in all nine sedimentary basins that had areas on offer, a record number in the bids held to date in this modality. The previous record was recorded in the Third Cycle, when 59 blocks were sold.

Brazilian Competition Law

Certain corporate transactions, including the acquisition of assets and the formation of joint ventures, consortia and collaborative agreements (the so-called *Contratos Associativos*), including those conducted under farm-in and farm-out agreements, are subject to the Brazilian Pre-Merger Control System if they meet the applicable thresholds, pursuant to Law No. 12,529, dated November 30, 2011. Accordingly, these transactions may be subject to both ANP's and the Brazilian Administrative Council for Economic Defense's prior approval and cannot be completed before such approvals are duly granted, pursuant to Article 88 of Law No. 12,529/2011. Failure to comply with this obligation exposes all the parties involved in the transaction to the following consequences: (i) fine ranging from R$60,000 to R$60.0 million; (ii) the transaction may be deemed null and void; and (iii) opening of an investigation for anticompetitive behavior due to the practices carried out post-closing.

Environmental Regulations

In view of the specific requirements set forth in the laws of certain locations in which we operate, a portion of our activities is subject to environmental licenses issued by federal, state or municipal environmental authorities. We strive to meet and adjust to the terms and conditions ser forth in these licenses.

Environmental Licensing

The Brazilian Environmental Policy, established by Law No. 6,938/1981, provides that all potentially or effectively polluting activities are subject to an environmental licensing process (without prejudice to other licenses and authorizations legally required). The environmental licensing process encompasses three different stages, including the granting of the preliminary license (*licença prévia*), the installation license (*licença de instalação*) and the operating license (*licença de operação*).

However, this licensing process may be simplified, encompassing only one stage, upon the issuance of the simplified environmental license (*licença ambiental simplificada*) or the single environmental license (*licença ambiental única*), subject to the laws and regulations of the involved licensing agencies and, to different extents, the characteristics of each project, including the region, size, construction characteristics, polluting potential and level of impact, among others.

In any event, the aforementioned environmental licenses expire and must be periodically and timely renewed. Pursuant to Complementary Law No. 140/2011, the renewal of any environmental license must be requested at least 120 days before the expiration date to be automatically extended until the environmental agency issues its final decision. Certain environmental licenses may set forth technical conditions for the development of activities that have an environmental impact, under penalty of cancellation of the relevant license.

Failure to obtain licenses or authorizations from the competent environmental agencies for the conception, construction, change, expansion and operation of activities and/or potentially polluting projects, or operations in disagreement with the issued environmental licenses, as well as to the non-compliance with the conditions set forth on such licenses may subject offenders to criminal and administrative penalties, in addition to the obligation to repair any environmental damages. Applicable administrative penalties to this issue include fines, ranging from R$500.00 to R$10.0 million, pursuant to Federal Decree No. 6,514/2008, which regulates Federal Law No. 9,605/1998. State and municipal governments may provide for environmental protection and impose fines in different amounts.

Solid Waste

The Brazilian Solid Waste Policy, established by Federal Law No. 12,305/2010, sets forth the principles, instruments, guidelines, targets and actions related to the integrated and environmentally adequate management of solid waste, except radioactive waste, which is subject to specific laws. Generators of solid waste are responsible for its environmentally adequate segregation, storage, transportation and final disposal, and may be required to repair any environmental damages resulting from the inadequate management of this waste.

The Brazilian Solid Waste Policy established the shared responsibility, pursuant to which the tasks and costs involved in the different stages of management of solid waste are shared by the entire production chain, in proportion to the liability of each of the involved parties. Accordingly, even though the civil liability for repairing environment damages is joint and several, strict and tort-based, the administrative liability for managing solid waste divides the burden among the parties involved in the chain.

Accordingly, the engagement of third parties to perform any of the stages of the management of solid waste, including the environmentally adequate final disposal, does not exempt us from liability for any environmental damage caused by the engaged third parties.

The inadequate disposal of solid waste may subject offenders to administrative, criminal and/or civil liability.

Pursuant to Federal Decree No. 6,514/2008, discharging solid, liquid or gaseous wastes or debris, oils or oily substances in violation of the requirements established by legislation, as well as failure, by the party with an obligation, to dispose of products, oil derivatives, packages, residues or substances in an environmentally appropriate manner when so determined by legislation, subjects offenders to potential administrative liability penalties, including fines of up to R$50.0 million. Pursuant to Federal Law No. 9,605/1998, or the Brazilian Environmental Crimes Law, discharging solid, liquid or gaseous wastes or debris, oils or oily substances in violation of the requirements established by legislation, subjects offenders to potential criminal liability, including imprisonment for one to five years and a fine. In the event of unintentional crime, offenders are subject to imprisonment for six months to one year and a fine. These penalties may be applied without prejudice to the obligation to repair the environmental damages.

Contaminated Areas

Contaminated areas are sites that have been confirmedly polluted by the disposal, accumulation, storage or infiltration of substances or waste, resulting in negative impacts on the assets to be protected.

Pursuant to Brazilian environmental laws, the owner and/or possessor of a real estate property located in an environmentally contaminated area may be held liable and required to remediate and repair the associated damages, whether they caused the damages or not, by determination of environmental agencies and the Prosecutor's Office.

Environmental civil liability for repairing the contamination of the soil and underground waters is strict, joint and several and is considered to be a *propter rem* obligation, which is an obligation that accompanies the real estate property.

Causing pollution of any nature in levels that result or may result in damage to human health or that cause the death of animals or a significant destruction of biodiversity is an administrative infraction that subjects offenders to administrative fines ranging from R$5,000.00 to R$50.0 million, as well as an environmental crime, and imposes the obligation to repair the environment.

Environmental Liability

Environmental liability encompasses the following different and independent liabilities: (i) civil liability; (ii) administrative liability; and (iii) criminal liability. These liabilities are different and independent because one single action may result in environmental liability at these three levels, including the application of administrative and criminal penalties, in addition to the obligation to repair the damage caused. Conversely, the lack of liability at any of these levels does not necessarily exempt offenders from liability on the other levels.

Environmental civil liability is strict, *i.e.*, it is not subject to the existence of fault. The confirmation of the damage and the causation between the damage and the activity of a company suffices to subject offenders to the obligation of repairing the damage. Irrespective of the existence of fault, the party that causes the pollution is required to indemnify and/or repair the damages caused to the environment and third parties as a result of the party's activities. Accordingly, environmental civil liability is attributed to the party that is directly or indirectly responsible for the activity that caused the environmental damage. Moreover, if the activity is conducted by more than one party and it is not possible to identify the contribution of each party to the environmental damage, government agencies and courts have been imposing joint and several liability on the party that is able to bear the entire environmental damage, having right of recourse against the other involved parties. Environmental civil liability is joint and several and is not subject to the statute of limitations. As a result, the engagement of third parties to provide any service in our units, including the suppression of vegetation, and the transportation and final disposal of waste, does not exempt us from liability for any environmental damages caused if these third parties do not perform their activities in compliance with environmental regulations. Brazilian civil liability environmental law provides for the piercing of the corporate veil of entities that commit environmental infractions whenever it represents an obstacle for repairing environmental damages. Potential criminal liability under the Brazilian Environmental Crimes Law applies to any individual or corporation that contributes to environmental crimes, upon confirmation of intent, *i.e.*, the free will to produce the result, or fault, *i.e.*, the lack of the necessary care, including negligence, recklessness or lack of skill. Accordingly, the imposition of criminal liability requires the confirmation of an action or omission, and the alleged conduct must be enumerated as a crime under the relevant laws. Potential criminal penalties for individuals include imprisonment; restriction of rights, including community services, temporary interdiction of rights, partial or full suspension of activities, pecuniary indemnification or house confinement (*recolhimento domiciliar*); and fines. Restriction of rights is an independent penalty and may replace imprisonment in certain cases. Potential criminal penalties for corporations include: restriction of rights, including the partial or full suspension of activities, temporary interdiction of facilities, construction or activity, or prohibition to contract with the government and obtain government subsidies, incentives or donations; community services; and fines. Individuals and corporations are subject to fines ranging from one-third of to 1,800 times the minimum wage in effect at the time of the facts, based on their culpability.

Potential administrative liability under the Brazilian Environmental Crimes Law, regulated by Federal Decree No. 6,514/2008, exists for all actions or omissions that violate the provisions on the use, enjoyment, promotion, protection and recovery of the environment. Administrative liability derived from an action or omission of the agent that results in the violation of any rule on environmental preservation, protection or regulation and, similarly to criminal liability, is subject to the confirmation of fault or intent, pursuant to the court precedents of the Superior Court of Justice (*Superior Tribunal de Justiça*). However, certain environmental agencies continue to impose strict administrative liability regarding environmental infractions. Administrative penalties include warning; fines of up to R$50.0 million, which may be doubled or tripled in the event of recidivism; destruction of the product whose production caused the environmental damage; suspension of the sale and manufacturing of the product; interdiction of the construction or activity; demolition of construction; suspension of tax benefits and the cancellation or interruption of credit facilities granted by government banks, in addition to the prohibition to contract with the government.

The Prosecutor's Office and environmental agencies may initiate administrative procedures to investigate any environmental damages that may be attributed to our activities. In these cases, we may enter into conduct adjustment instruments (*Termos de Ajustamento de Condutas*), or TACs, and/or generic commitment instrument (*Termos de Compromissos*), or TCs, with the relevant authorities, assuming specific obligations for a certain time. TACs and TCs are out-of-court enforceable instruments and, as a result, in the event of full or partial non-compliance with TACs and/or TCs, we may be subject to risks and penalties, including the payment of fines, enforcement of these instruments and the filing of proceedings with courts.

In addition to licenses, we may be required to obtain certain authorizations issued by environmental agencies, including in regard to the suppression of vegetation, use of water resources, treatment of effluents and management of waste, among others. Also, we are required to observe applicable rules to preserve and (re)forest protected areas as well as rules related to impacts on traditional communities and historical heritage.

Carbon credits and the Brazilian Greenhouse Gas Emissions Trading System

On December 21, 2023, the Brazilian House of Representatives approved a bill to create a Brazilian Greenhouse Gas Emissions Trading System. Subject to the approval of the bill by both houses of the Brazilian parliament, Karoon, which has facilities or sources that may emit greater than 10,000 tCO_2/e per year, is likely to be considered a regulated entity under the scope of the regulation, which may impose reporting and other requirements on us. Under the currently proposed rules, we would be required to acquire assets, which are also known as SBCE assets, through the trading system. These assets include Brazilian Emissions Quotas, which are similar to the European Union Emissions Trading System, and Verified Emission Reduction Certificates. A portion (which is not yet defined) of the Verified Emission Reduction Certificates could be originated from voluntary carbon credits that meet certain legal requirements. As of the date of this offering memorandum, the implementation and timeline for a Brazilian carbon market remains uncertain. See also "Risk factors—Risks relating to our regulatory, tax and legal environment—Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position."

Data Protection and the Brazilian General Data Protection Law

Data privacy and protection laws have evolved in recent years to provide for more detailed rules on how companies may process personal data, *i.e.*, any information related to an identified or identifiable individual.

Until August 2018, when the Brazilian General Data Protection Law (Law No. 13,709/18, or LGPD), was enacted, practices related to the processing of personal data were regulated by sparse legislation and industry-specific regulations.

With the enactment of LGPD on September 18, 2020, Brazil has adopted more robust rules for the processing of personal data, with stronger requirements, applicable across all industries. Inspired by the European Union's General Data Protection Regulation (the GDPR), the LGPD creates a framework in which individuals have more control over their personal data and companies that process this type of information have more responsibilities.

Privacy rights in Brazil are also protected by the Brazilian Federal Constitution and Law No. 10,406/02, or the Brazilian Civil Code of 2002. In addition, Brazilian Constitutional Amendment No. 115 of February 10, 2022, includes the protection of personal data among the fundamental rights and guarantees provided for in the Brazilian Federal Constitution.

The LGPD applies to individuals and public and private entities, regardless of the country where they are based or where the data is hosted, provided that (i) the data processing activity is carried out in Brazil; (ii) the data processing activity is intended to offer goods or services to, or processes data of, individuals located in Brazil; or (iii) the personal data involved in the data processing have been collected in Brazil. The Brazilian General Data Protection Law applies to all industries and businesses processing personal data and is not restricted only to data processing activities carried out via digital media and/or over the internet, but is also applied in the physical environment.

The LGPD provides for, among others, the obligation of transparency by data controllers, the rights of data subjects, the obligation to define the legal basis for processing personal data, the obligation to appoint a data protection officer (*encarregado*), rules applicable to information security incidents involving personal data, the implementation of a privacy governance program as a best practice, as well as the requirements and obligations for international data transfers.

In addition, the LGPD establishes the role of the National Data Protection Authority (*Autoridade Nacional de Proteção de Dados*), or ANPD, which is responsible for protecting, implementing and inspecting compliance with the LGPD, as well as for: (i) investigation of data processing incidents, including the power to enact standards and procedures, interpretation of the LGPD and power to request information from data controllers and processors; (ii) enforcement, in cases of violations, via administrative proceedings; and (iii) education, including disseminating information and fostering awareness of the LGPD and safety measures, promoting best practices for services and products that facilitate data control, and producing studies about national and international practices for the protection of personal data and privacy, among others.

We have a personal data privacy governance program to comply with the guidelines and requirements presented by the LGPD. Furthermore, we have data protection policies and safeguards based on best industry practices. As of the date of this offering memorandum, we have adopted measures in compliance with the LGPD, such as the appointment of a personal data protection officer or DPO. We have appointed a specialized legal consultancy office to perform the role of our data protection officer. The data protection officer is responsible for, among others, providing the necessary technical and legal support to assist us in the effective implementation of our privacy governance program, ensuring that we process personal data in compliance with privacy and data protection rules, as well as responding to data subject requests and interacting with the ANPD.

Our privacy and personal data protection governance program demonstrates our commitment to adopting internal processes and policies that ensure comprehensive compliance with standards and best practices relating to data protection and the privacy of data subjects, as well as cybersecurity.

We also implemented privacy notices to provide information on the processing activities we carry out. These include (i) an internal privacy and data protection notice, which applies to all internal employees who have or had a relationship with us; and (ii) a privacy and data protection notice with the aim of bringing transparency to data subjects such as customers, business partners, investors and any other interested party that has a relationship with us, as well as service providers, suppliers, employment candidates and all groups and companies that have or had a relationship with us.

For additional information, see "Risk factors—Risks relating to our regulatory, tax and legal environment—Our business, practices and policies are subject to risks associated with non-compliance with the Brazilian General Data Protection Law and could be adversely affected by the application of penalties, including fines and indemnifications."

Regulatory overview – US Gulf of Mexico

Within the United States, our operations are subject to complex and stringent federal, state and local laws and regulations that govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be discharged or emitted into the environment, and the handling, treatment, storage and disposal of waste material. There are also laws and regulations requiring the remediation of releases of hazardous substances, pollutants and contaminants into the environment, including in connection with waste materials that are transported from offsite facilities and disposed of in onshore facilities.

Environmental regulation

The federal environmental laws and regulations applicable to us and our operations include, among others, the following:

- *U.S. Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA").* CERCLA and analogous state statutes impose liability for the investigation and cleanup of releases of hazardous substances, pollutants, and contaminants into the environment on, among others, current and former owners and operators of contaminated properties, and parties that disposed of, or arranged for the disposal of, such substances at third-party disposal sites. CERCLA liability is joint and several. A liable party may be required to clean up all of the contamination at a site even if it contributed only a percentage of the total substances released at the site. CERCLA liability is no fault. A liable party may be required to clean up contamination even if the original activities, including disposal activities, accorded with all then applicable regulatory requirements. Although CERCLA generally exempts "petroleum" from regulation, in the course of our operations, we could generate wastes that fall within CERCLA's definition of hazardous substances, pollutants or contaminants, and may have disposed of these wastes at disposal sites, owned and operated by others, where releases to the environmental subsequently occurred.

- *U.S. Clean Water Act ("CWA").* Discharges into waters of the United States are limited by the CWA and analogous state statutes. The CWA prohibits any discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, except in compliance with permits issued by federal and state governmental agencies. These discharge permits also include monitoring and reporting obligations. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may result in administrative, civil or criminal enforcement actions. Violations of the CWA can result in suspension, debarment or the imposition of statutory disability, each of which prevents companies and individuals from participating in government contracts and receiving some non-procurement government benefits. The CWA also requires the preparation of oil spill response plans and spill prevention, control and countermeasure plans.

- *U.S. Oil Pollution Act ("OPA").* OPA holds owners and operators of offshore oil production or handling facilities, including the lessee or permittee of the area where an offshore facility is located, strictly liable for the costs of removing oil discharged into waters of the United States and for certain damages from such spills. OPA assigns joint and several, and strict, liability, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. OPA's damages liability cap is currently $167.8 million; however, a party cannot take advantage of liability limits if a spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulations, or if the party failed to report a spill or cooperate fully in the clean-up. OPA also requires responsible parties to maintain evidence of financial responsibility in prescribed amounts. OPA currently requires a minimum financial responsibility demonstration of between $35 million to $150 million, based on a worst-case oil spill discharge volume, for companies operating on the OCS.

- *U.S. Clean Air Act ("CAA").* The CAA and analogous statutes restrict the emission of air pollutants and affect both onshore and offshore oil and natural gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the Environmental Protection Agency ("EPA") has developed, and continues to develop, more stringent regulations governing emissions of toxic air pollutants.

- *U.S. Endangered Species Act ("ESA"); U.S. Migratory Bird Treaty Act ("MBTA") and U.S. Marine Mammals Protection Act ("MMPA").* The ESA restricts activities that may affect federally identified endangered and threatened species or their habitats. Additionally, the MBTA implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit. The MMPA similarly prohibits the taking of marine mammals without authorization.

  The U.S. Fish and Wildlife Service ("FWS") under former President Trump issued a final rule on January 7, 2021, limiting the scope of the MBTA, including by interpreting the MBTA as only prohibiting the intentional take of migratory birds (i.e., actions "directed at" migratory birds, their nests or their eggs). In October 2021, however, the FWS under the Biden Administration revoked the Trump Administration's rule and returned to its prior interpretation that both intentional and incidental takes of migratory birds are prohibited. The FWS also published an advanced notice of proposed rulemaking to codify a general prohibition on incidental takes while establishing a process to regulate or permit exceptions to such a prohibition.

  The FWS under former President Trump also issued rules limiting the scope of the ESA. These have largely been revoked or superseded by rules issued by the FWS under President Biden. For example, on March 28, 2024 the FWS finalized three rules under the ESA that revise Trump-era regulations and strengthen protections for plants and animals. The new rules include restoring the so-called blanket rule, which automatically extends protection for endangered species to threatened species; affirming that listing determinations are made without reference to possible economic impacts; and clarifying standards for delisting species. The rules are expected to become effective on May 6, 2024. On April 12, 2024, the FWS also issued a final rule that expedites the process of issuing enhancement and survival permits, and incidental take permits. Under the rule, an enhancement or survival permit is appropriate for authorizing takes for scientific purposes or to enhance the survival of a species, while an incidental permit remains appropriate for authorizing takes incidental to lawful resource extraction, commercial development, and energy infrastructure.

  Additionally when the FWS makes determinations on the listing of species as threatened or endangered under the ESA, litigation with respect to the listing or non-listing may result in more fulsome protections for non-protected or lesser-protected species. Moreover, the FWS or the National Marine Fisheries Service ("NMFS") may designate critical habitat that it believes is necessary for survival of a threatened or endangered species. A critical habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for oil and natural gas development. For example, in April 2019, the NMFS listed the Rice's whale, determined to be a subspecies of the Bryde's whale, as endangered under the ESA. On July 24, 2023, NMFS proposed to designate approximately 28,270.65 square miles of the Gulf of Mexico as critical habitat for the Rice's whale. NMFS is currently reviewing comments and is expected to issue a final critical habitat designation for the Rice's whale in 2024. These statutes may result in operating restrictions or a temporary, seasonal or permanent ban in affected areas.

- *U.S. Resource Conservation and Recovery Act ("RCRA").* RCRA generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy," the EPA and state agencies may regulate these wastes as solid wastes. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in increased costs to manage and dispose of generated wastes. Also, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

- *U.S. National Environmental Policy Act ("NEPA").* NEPA requires federal agencies, including the DOI, to consider the impacts their actions have on the human environment, and to prepare detailed statements for major federal actions having the potential to significantly impact the environment. These requirements can lead to additional costs and delays in permitting for operators as the DOI or its bureaus may need to prepare Environmental Assessments ("EA") and more detailed Environmental Impact Statements ("EIS") in support of its leasing and other activities that have the potential to significantly affect the quality of the environment. If the EA indicates that no significant impact is likely, then the agency can release a finding of no significant impact and carry on with the proposed action. Otherwise, the agency must then conduct a full-scale EIS.

  The Biden Administration announced in October 2021 that it intended to issue new rules that would authorize agencies to consider direct, indirect and cumulative effects of major federal actions including upstream and downstream GHG emissions impacts of fossil fuel projects, allowing agencies to determine the purpose and need of a project, which allows consideration of less-harmful alternatives, and affording agencies greater flexibility in crafting their own NEPA procedures, consistent with Council on Environmental Quality ("CEQ") regulations, so as to meet the agencies' and public's needs. In April 2022, the CEQ issued a final rule in line with the proposed changes, a move considered as "Phase I" of the Biden Administration's two-phased approach to modifying NEPA. On July 28, 2023, the CEQ announced a "Phase 2" Notice of Proposed Rulemaking, the "Bipartisan Permitting Reform Implementation Rule," which revises the implementing regulations of the procedural provisions of NEPA and implements the amendments to NEPA included in the June 3, 2023, Fiscal Responsibility Act of 2023. The public comment period for the proposed rule closed on September 29, 2023, and the final rule is expected in the second quarter of 2024. Additionally, in January 2023, the CEQ released guidance to assist federal agencies in assessing the GHG emissions and climate change effects of their proposed actions under NEPA. The CEQ's interim guidance, effective upon publication, encourages agencies to consider, among other things, effects from upstream and downstream GHG emissions of fossil fuel projects and, in many cases, use estimates of the social costs of GHG emissions when communicating those findings to the public. The NEPA process involves public input through comment. These comments, as well as the agency's analysis of the proposed project, can result in changes to the nature of a proposed project, such as by limiting the scope of the project or requiring resource-specific mitigation. The adequacy of the agency's NEPA process can be challenged in federal court by process participants. This process may result in delaying the permitting and development of projects and result in increased costs.

- *U.S. Bureau of Ocean Energy Management ("BOEM"), the U.S. Bureau of Safety and Environmental Enforcement ("BSEE"), and Office of Natural Resources Revenue ("ONRR") requirements*. Federal oil and natural gas leases in the U.S. Gulf of Mexico are subject to extensive regulation by BSEE, the BOEM and the ONRR under the purview of the DOI. Federal leases are awarded by BOEM based on competitive bidding with relatively standardized lease terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the federal Outer Continental Shelf Lands Act ("OCSLA"). For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of their operations. Lessees must obtain a permit from BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandoning of wells on the OCS, calculation of and valuation of production related to royalty payments, and decommissioning of facilities, structures and pipelines.

The Biden Administration has taken a number of actions to adopt more stringent safety, permitting and performance requirements. For example, on August 23, 2023, BSEE published a final well control rule for drilling, workover, completion and decommissioning operations, revising the 2019 rule and increasing the requirements for blowout preventer systems ("BOPs") and other well control and operations requirements. The final rule requires, among other things, that BOPs are always able to close and seal the wellbore to the well's maximum anticipated surface pressure, failure analysis and investigations start within 90 days of an incident, failure data is reported to both a designated third party and BSEE, and independent third-party qualifications are submitted to BSEE with associated permit applications.

There has been substantial uncertainty with respect to BOEM's financial assurance requirements in recent years and BSEE's approach to predecessor liability for decommissioning obligations. In April 2023, BSEE published its Final Rule entitled, "Risk Management, Financial Assurance, and Loss Prevention—Decommissioning Activities and Obligations," wherein BSEE clarified decommissioning responsibilities for right-of-use and easement grant holders and formalized BSEE's policies regarding performance by predecessors ordered to decommission OCS facilities. The final rule withdraws a rule proposed during the Trump Administration that sought to amend BSEE's regulations requiring the agency to proceed in reverse chronological order against predecessor lessees, owners of operating rights and grant holders when requiring such entities to perform their accrued decommissioning obligations upon failure to perform by current lessees, owners, or holders. Under the final rule, BSEE may issue an order to predecessors to perform accrued decommissioning obligations, including beginning maintenance and monitoring within thirty days, designating an operator for decommissioning within ninety days, and submitting a decommissioning plan within one hundred fifty days.

In addition, on April 15, 2024 BOEM announced a final rule that substantially revises the supplemental financial assurance requirements applicable to offshore oil and gas operations. The final rule is expected to be published in the *Federal Register* later in April and to become effective 60 days after publication. The rule changes the criteria used to determine whether OCS lease and grant holders are required to secure supplemental financial assurance. The rule replaces the 5-point test (based on financial capacity; projected financial strength; business stability; record of compliance with existing rules and regulations; and reliability) with a a simplified test: (i) the credit rating of the lessee and, where applicable, (ii) the ratio of the value of proved oil and gas reserves of the lease to the estimated decommissioning liability associated with the reserves. Under the rule, BOEM will no longer consider or rely upon the financial strength of predecessors in determining whether, or how much, supplemental financial assurance should be provided by current lessees and grant holders. BOEM will not require supplemental financial assurance above the base bond requirements in three cases: (i) where a lessee has an investment grade credit rating (i.e., a credit rating from a Nationally Recognized Statistical Ratings Organizations ("NRSRO") that is greater than or equal to either BBB- from S&P or Baa3 from Moody's, or its equivalent, or a proxy credit rating greater than or equal to either BBB- or Baa3, as determined by the Regional Director of such NRSRO and based upon a company's audited financial information with an accompanying auditor's certificate); (ii) where there are multiple co-lessees on a lease and any one of those lessees meets the credit rating threshold; or (iii) for any lease on which all lessees are rated below investment grade, where the value of the lease's proved oil and gas reserves is at least three times that of the estimated decommissioning cost estimate. We are currently assessing the impact of the revised rule.

Separately, in August 2021, BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements currently applicable to all sole liability properties and now to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable requirements related to financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM.

Health and safety

The joint venture is also subject to the requirements of the Occupational Safety and Health Administration ("OSHA") and analogous state statutes, where applicable. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes, where applicable, require that we organize and/or disclose information about hazardous materials used or produced in our operations. Such laws and regulations also require that workplaces meet prescribed safety standards and provide for compensation to employees injured as a result of our failure to meet these standards as well as civil and/or criminal penalties in certain circumstances. We believe that our operations are in substantial compliance with all applicable existing laws and regulations.

Other oil and gas industry regulations

The oil and natural gas industry is extensively regulated by numerous U.S. federal, state and local authorities. Rules and regulations affecting the oil and natural gas industry are under consistent review for amendment or expansion, which could increase the regulatory burden and the potential sanctions for noncompliance. Relatedly, numerous federal and state departments and agencies are authorized to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply.

Exploration and production by our joint venture are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Our joint venture may face requirements for (i) the location of wells; (ii) the method of drilling and casing wells; (iii) the plugging and abandonment of wells and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines; and (iv) the produced water and disposal of wastewater, drilling fluids and other liquids and solids utilized or produced in the drilling and extraction process.

Our joint venture's operations on federal oil and natural gas leases in the US Gulf of Mexico are subject to regulation by the BSEE, the BOEM and the Office of Natural Resources Revenue, all of which are agencies of the DOI. The BSEE and the BOEM work to ensure the development of energy and mineral resources on the OCS is done in a safe and environmentally and economically responsible way. The Office of Natural Resources Revenue performs the offshore royalty and revenue management functions of the former Minerals Management Service.

Leasing. The US federal government cannot conduct offshore lease sales without the development and approval of an OCS Program. The OCSLA authorizes the Secretary of the Interior to establish a schedule of lease sales for a five-year period. There is no requirement under the OCSLA that mandates any sales in any locations, nor does the law prescribe any specific timing for the development of the OCS Program. These leases are awarded by the BOEM based on competitive bidding and contain relatively standardized terms. Prior to commencement of offshore operations, lessees must obtain the BOEM's approval for exploration, development and production plans. In addition to permits required from other agencies such as EPA, lessees must obtain a permit from the BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the OCS, calculation of royalty payments and the valuation of production for this purpose, and decommissioning of facilities, structures and pipelines.

In January 2021, President Biden issued an executive order suspending new leasing activities for oil and natural gas exploration and production on federal lands and offshore waters pending review and reconsideration of federal oil and natural gas permitting and leasing practices. After a group of states challenged the executive order, a federal judge required the DOI to stop the leasing pause.

In August 2022, Congress passed the IRA, which required the BOEM to offer at least two million acres for oil and natural gas leasing in the OCS. The IRA also raised the royalty rate for certain offshore leases from 12.5% to 16.67% and capped the rate at 18.75% for ten years.

In November 2021, the DOI released its report on federal oil and natural gas leasing and permitting practices. The report included recommendations in respect to the offshore sector, including adjusting royalty rates to ensure that the full value of leased tracts are captured, strengthening financial assurance coverage amounts that are required by operators, and establishing "fitness to operate" criteria that companies would need to meet in respect of safety, environmental and financial responsibilities in order to operate in the OCS.

In September 2023, consistent with the requirements of the IRA concerning offshore conventional and renewable energy leasing, the DOI announced its proposed 2024 – 2029 OCS Program. The proposed OCS Program includes a maximum of three potential oil and natural gas lease sales in the US Gulf of Mexico scheduled in 2025, 2027 and 2029.

Decommissioning and financial assurance requirements. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities in the OCS. Currently the BOEM requires all lessees of an OCS oil and natural gas lease to post base bonds ranging from US$50,000 to US$3.0 million in addition to supplemental financial assurance determined based on the lessee's ability to carry out present and future financial obligations. See "Environmental regulations—U.S. Bureau of Ocean Energy Management ("BOEM"), the U.S. Bureau of Safety and Environmental Enforcement ("BSEE"), and Office of Natural Resources Revenue ("ONRR") requirements."

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The US Federal Energy Regulatory Commission (the "FERC") has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in 1992, the interstate natural gas transportation and marketing system allows non-pipeline natural gas sellers, including producers, to effectively compete with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the effect of Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. The rates for such storage and transportation services are subject to the FERC ratemaking authority, and the FERC may apply cost-of-service principles or allow a pipeline to negotiate rates. Similarly, the natural gas pipeline industry is subject to state regulations, which may change from time to time.

The OCSLA, which is administered by the BOEM and the FERC, requires that all pipelines operating on or across the OCS provide open access, non-discriminatory transportation service. One of the FERC's principal goals in carrying out the OCSLA's mandate is to increase transparency in the OCS market, to provide producers and shippers assurance of open access service on pipelines located on the OCS, and to provide non-discriminatory rates and conditions of service on such pipelines. The BOEM issued a final rule, effective August 2008, which implements a hotline, alternative dispute resolution procedures, and complaint procedures for resolving claims of having been denied open and nondiscriminatory access to pipelines in the OCS.

In 2007, the FERC issued rules ("Order 704") requiring that any market participant that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report such sales and purchases to the FERC to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with the FERC's policy statement on price reporting. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state legislatures, state commissions and the courts. The natural gas industry historically has been very heavily regulated. As a result, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and the states will continue. See "Risk factors—Risks relating to our regulatory, tax and legal environment—Our business is subject to extensive laws and regulations that are subject to change in ways that could adversely affect our business and financial position."

Oil and NGLs transportation rates. Other than as described above, our sales of liquids, which include oil, condensate and NGLs, are not currently regulated and are transacted at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction. The price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. Interstate transportation rates for oil, condensate, NGLs and other products are regulated by the FERC. In general, interstate oil, condensate and NGL pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. The FERC has established an indexing system for such transportation, which generally allows such pipelines to take an annual inflation-based rate increase.

In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes and regulations. As it relates to intrastate oil, condensate and NGL pipelines, state regulation is generally less rigorous than the federal regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests, which are infrequent and are usually resolved informally.

Climate Change. The threat of climate change continues to attract considerable public, governmental and scientific attention in the United States. President Biden has made addressing climate change, including the restriction or elimination of greenhouse gas ("GHG") emissions, a priority in his administration.

The IRA includes a methane emissions reduction program that amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems by 2024.

In April 2024, the EPA issued a final rule expanding the scope of the Greenhouse Gas Reporting Program for petroleum and natural gas facilities. Among other things, the rule expands the emissions events that are subject to reporting requirements to include "other large release events," which capture abnormal methane emission events that are not fully accounted for using existing methods, and applies reporting requirements to certain new sources and sectors. The rule will become effective on January 1, 2025, and reporters will implement most of the changes in the 2025 reporting year with reports submitted by March 31, 2026.

In January 2024, the EPA proposed a new rule implementing the IRA's methane emissions charge. The proposed rule includes potential methodologies for calculating the amount by which a facility's reported methane emissions are below or exceed the waste emissions thresholds and contemplates approaches for implementing certain exemptions created by the IRA. The methane emissions charge imposed under the Methane Emissions and Waste Reduction Incentive Program for 2024 would be $900 per ton emitted over annual methane emissions thresholds, and would increase to $1,200 in 2025, and $1,500 in 2026. The implementation of revised air emission standards is likely to increase costs and regulatory burdens on the oil and natural gas industry, especially for smaller operators and operators of older oil and natural gas wells.

The threat of climate change also continues to attract considerable public, governmental and scientific attention in foreign countries. Numerous proposals have been made at the international levels of government to monitor and limit emissions of GHG as well as to restrict or eliminate future emissions. Most recently, at the 28th Conference of the Parties ("COP28"), member countries entered into an agreement that calls for actions toward achieving, at a global scale, a tripling of renewable energy capacity and doubling energy efficiency improvements by 2030. The goals of the agreement include, among other things, accelerating efforts toward the phase-down of unabated coal power, phasing out inefficient fossil fuel subsidies and other measures that drive the transition away from fossil fuels in energy systems. In February 2021, the Biden administration rejoined the Paris Agreement. Pursuant to its obligations as a signatory to the Paris Agreement, the United States has set a target to reduce its GHG emissions by 50% to 52% by the year 2030 as compared with 2005 levels and has agreed to provide periodic updates on its progress. In addition, in November 2021, the United States signed the Global Methane Pledge, a pact that aims to reduce global methane emissions by at least 30% below 2020 levels by 2030. The impacts of these pledges and agreements, and any legislation or regulation promulgated to fulfill the United States' commitments under the COP28 agreement, the Paris Agreement, or the Global Methane Pledge, or other international conventions, cannot be predicted at this time. See "Risk factors—Risks relating to our regulatory, tax and legal environment—Laws regulating greenhouse gas emissions could adversely affect the cost, manner and feasibility of doing business and demand for the oil and gas that we produce."

MANAGEMENT

Board of directors

The following table sets forth certain information regarding our directors.

Name	Age	Position(s)
Dr. Julian Fowles	60	Chief Executive Officer and Managing Director
Peter Botten	69	Independent Non-Executive Chair
Peter Turnbull	65	Independent Non-Executive Director
Clark Davey	67	Independent Non-Executive Director
Luciana Bastos De Freitas Rachid	66	Independent Non-Executive Director
Carlos Tadeu da Costa Fraga	66	Independent Non-Executive Director
Melissa Holzberger	48	Independent Non-Executive Director
Joanne Palmer	49	Independent Non-Executive Director

Dr. Julian Fowles, Chief Executive Officer and Managing Director

Dr Julian Fowles joined our board as chief executive officer and managing director on November 27, 2020.

Dr Fowles started his career with Shell International where he spent 17 years working across the upstream sector in Europe, West Africa, Australasia, South Asia and Latin America, including 5 years as the exploration and new ventures manager in Shell Brazil. Following Shell, he held senior executive positions with Cairn India, Petra Energia, and most recently Oil Search, where he firstly led exploration and new business and then the Papua New Guinea operated and non-operated oil and liquefied natural gas production and development businesses. Leaving Oil Search in late 2018, Dr. Fowles joined the boards of Central Petroleum and FAR Limited in 2019 as an independent non-executive director, roles he relinquished prior to joining us.

Dr Fowles is a graduate of the Australian Institute of Company Directors. He holds a bachelor of science (hons) degree in geology from the University of Edinburgh and a PhD from the University of Cambridge. Dr. Fowles also holds a graduate diploma in applied finance and investment from the Australian Securities Institute.

Peter Botten, Independent Non-Executive Chair

Mr. Botten joined our board on October 1, 2020, and was appointed as the chair of the board on November 23, 2023. He is also a member of the audit and risk committee and a member of the sustainability and operational risk committee. In addition to serving on our board, Mr. Botten currently serves as chair of Aurelia Metals Ltd and chair of Conrad Asia Energy.

Mr. Botten is a former chief executive and business leader with over 40 years of experience in the international resources sector, including as chief executive officer of Oil Search for 26 years. Mr. Botten's executive experience spanned aspects of the upstream petroleum sector including in upstream oil and gas exploration, development and production operations through his involvement in projects in PNG, Australia, Africa, the Middle East and North America. Mr. Botten also has experience in governing and growing ASX-listed companies and other business entities.

Mr Botten holds a bachelor of science degree in geology from the Imperial College of Science and Technology, London University and the Royal School of Mines.

Mr. Peter Turnbull, Independent Non-Executive Director

Mr. Turnbull joined us as independent non-executive director on June 6, 2014. He is also the chairman of our people and culture committee and a member of our audit, risk and governance committee and sustainability and operational risk committee. In addition to serving on our board, Mr. Turnbull currently serves as chair of Calix Limited and chair of Auxita Pty Ltd.

Mr. Turnbull has over 25 years of senior executive and corporate legal experience with Australia's listed and unlisted public companies including Newcrest Mining, BTR Nylex and Energex.

Mr. Turnbull also has corporate, regulatory and government policy experience gained through working with the Australian Securities and Investments Commission and the Hong Kong Securities and Futures Commission. Mr. Turnbull is a former President of the Chartered Governance Institute based in London, a former member of the ASIC Corporate Governance Consultative Panel, a Life Member of the Governance Institute of Australia and a member of the Order of Australia.

Mr. Turnbull holds a bachelor of commerce degree and an LLB degree from the University of Melbourne.

Clark Davey, Independent Non-Executive Director

Mr. Davey joined us as independent non-executive director on October 1, 2010. He is also the chairman of our audit, risk and governance committee and a member of our people and culture committee.

Mr. Davey has over 30 years of experience in the Australian natural resources industry as a taxation consultant to oil and gas and mining companies. Mr. Davey was a partner at Price Waterhouse and PricewaterhouseCoopers specializing in the natural resources industry. For a number of years, he held resource industry leadership roles within both firms. Mr. Davey is a member of the Taxation Institute of Australia and the Australian Institute of Company Directors.

Mr. Davey's prior experience spans company income tax, petroleum resource rent taxation in Australia and assisting with accounting and capital management. He has assisted Australian companies with tax management of their joint venture interests and has had considerable experience with merger and acquisition transactions. He has also assisted companies expand their resource industry interests internationally.

Mr Davey holds a bachelor of commerce degree from the University of Melbourne.

Luciana Bastos De Freitas Rachid, Independent Non-Executive Director

Ms. Bastos De Freitas Rachid joined us as independent non-executive director on August 26, 2016. She is also chair of our sustainability and operational risk committee.

Ms. Bastos De Freitas Rachid has over 35 years of experience in the oil and gas industry in both technical, commercial and senior leadership roles in Brazil, including 20 years in the exploration and production division of Petrobras. She has represented Petrobras as chairperson of Transportadora Brasileira Gasoduto Bolívia-Brasil S.A, and Gás Brasiliano Distribuidora S.A as well as a director of Transportadora Associada de Gás, Companhia de Gás de Minas Gerais and Companhia Paranaense de Gás.

Ms. Bastos De Freitas Rachid has technical experience across project evaluation, development and management roles. Specific experience includes Marlim Leste asset manager, the design of the first offshore platforms in the Campos Basin, the production, handling and processing of natural gas onshore and offshore, the coordination of the Petrobras exploration and production deepwater strategic project and a variety technical and economic feasibility studies on major projects including participation in the first Petrobras project finance deals.

Ms. Bastos De Freitas Rachid has also held positions in the Petrobras commercial team including executive manager of investor relations, executive manager of financial planning and risk management, general manager of corporate affairs, general manager of marketing and trading, executive manager for logistics and investments in natural gas and chief executive officer Transportadora Brasileira Gasoduto Bolivia Brazil and most recently chief executive officer of Transportadora Associada de Gas SA.

Ms. Bastos De Freitas Rachid holds a bachelor of science degree in chemical engineering from Universidade Federal do Rio de Janeiro.

Carlos Tadeu da Costa Fraga, Independent Non-Executive Director

Mr. Fraga joined us as independent non-executive director on August 26, 2022. He is also a member of the sustainability and operational risk committee. Mr. Fraga currently serves as a board member at Vast Infraestrutura (formerly Açu Petróleo), at the Brazilian Institute for Petroleum, Gas and Biofuels and at Radix Engenharia e Software.

Mr. Fraga has 40 years of experience in the oil and gas sector, including 23 years as an executive at Petrobras. Mr. Fraga held various positions at Petrobras over his career, including as Campos Basin production general manager, Gulf of Mexico exploration and production operations manager, board member Petrobras Argentina SA, general manager – domestic oil and gas production, executive manager – exploration and production Brazil – south and southeast regions, executive manager – research and development and exploration and production executive manager – pre-salt developments.

Mr. Fraga is a former chief executive officer of Prumo Logistica and of the Porto do Açu, a former chief technology officer at Gran Energia, as well as a former board member of Gran Bio, GranIHC, Ultrapar, MRO Logistics, Ferroport, Gás Natural do Açu and Porto do Açu (being the chairman at the last three). Mr. Fraga has also served as a board member of several technology institutions in Brazil.

Mr. Fraga holds a bachelor of engineering degree from the Universidade Federal do Rio de Janeiro and is a post-graduate in Petroleum Engineering from Universidade Petrobras. He has also attended executive education programs at University of Alberta (management and regulation in the petroleum industry), Columbia University (executive education in business administration), INSEAD (technology management), London School of Economics (strategic leadership), and Brazilian Institute for Corporate Governance (board member).

Melissa Holzberger, Independent Non-Executive Director

Ms. Holzberger joined us as independent non-executive director on April 19, 2024.

Ms. Holzberger has over 20 years of experience in the international energy and resources sector. She is currently a non-executive director of Argo Investments Ltd, Paladin Energy Ltd, and Intermodal Terminal Company, and a member of the Federal Government's Australian Radiation Protection and Nuclear Safety Agency's Radiation, Health and Safety Advisory Council. Her former directorships include Silex Systems Ltd and Karting Australia.

Ms. Holzberger has also previously worked with BHP Group Ltd (including with its former BHP Petroleum assets) and Rio Tinto plc, and has acted as an adviser to multinational and Australian companies. She has experience in highly regulated industries, legal, risk and compliance oversight and sustainability, environmental, social and governance matters.

Ms. Holzberger holds a master of laws degree in Resources Law from the University of Dundee in Scotland, a bachelor of laws degree and bachelor of arts degree from the University of Adelaide. She is also a Fellow of the Governance Institute of Australia.

Joanne Palmer, Independent Non-Executive Director

Ms. Palmer joined us as independent non-executive director on April 19, 2024.

Ms. Palmer has over 27 years of professional experience providing audit and assurance services, with previous positions at EY and Pitcher Partners. Her international experience spans over 25 years as a former external auditor and advisor to United Kingdom and Australian companies operating in Africa, Europe, America and Australasia.

During her executive career at EY, Ms. Palmer worked primarily in the assurance practice and led EY's financial accounting advisory services team in Perth. Mainly working in the resources sector, she assisted multinational companies, mid-caps and junior explorers by providing external audit services, technical accounting, regulatory advice and finance function support services with a focus on transactions and M&A.

Ms. Palmer currently serves as a non-executive director on the boards of listed companies Paladin Energy, St Barbara, Sierra Rutile Holdings, and unlisted NextOre. She serves as the chair of the audit and risk committees of each of these companies, and is also a member of various additional committees of those boards.

Ms. Palmer holds a bachelor of science degree in Mathematics and Statistics from the University of Birmingham and is a Fellow of the Institute of Chartered Accountants in England and Wales, a Fellow of Chartered Accountants Australia and New Zealand, a former Registered Company Auditor and a Graduate Member of the Australian Institute of Company Directors.

Executive management

The following table sets forth certain information regarding the members of our executive management. See "—Board of directors" for more information in relation to our managing director and chief executive officer, Dr. Julian Fowles.

Name	Age	Position(s)
Dr Julian Fowles	60	Managing Director and Chief Executive Officer
Ray Church	58	Executive Vice President – Chief Financial Officer
Stephen Power	63	Executive Vice President Commercial
Roland Hamp	58	Executive Vice President Technical
Daniel Murnane	45	Executive Vice President – General Counsel and Company Secretary

Dr Julian Fowles is our chief executive officer, a position he has held since 2020. For further information, see "—Board of directors."

Ray Church, Executive Vice President – Chief Financial Officer

Mr. Church has served as our executive vice president – chief financial officer since 2021. Mr Church has more than 36 years of international experience in finance roles. He has worked in multiple jurisdictions, including the United States, Papua New Guinea, Kazakhstan, Russia and China, as well as Europe and Australia.

Mr. Church has more than two decades of oil and gas experience, having previously held the position of vice president, finance at TNK-BP and a variety of senior finance and commercial roles at Chevron Corporation. Mr. Church was also the chief financial officer at UGL Limited. He holds a bachelor of commerce degree from James Cook University and is a chartered accountant.

Stephen Power, Executive Vice President Commercial

Mr. Power has served as our executive vice president commercial since 2021.

Mr. Power is a commercial lawyer with more than 35 years of experience advising clients in the energy and resources industry in Australia and overseas, including South America, North America, West Africa and the UK.

Mr. Power is qualified as a Corporate Legal Practitioner in Victoria, Australia and holds a Bachelor of Jurisprudence and a bachelor of Laws degree from the University of Western Australia.

Roland Hamp, Executive Vice President Technical

Mr. Hamp has served as our executive vice president technical since 2023.

Mr. Hamp has more than 35 years of experience in the oil and gas sector, holding various technical and management positions in the UK and Australia, primarily with Enterprise Oil plc and Woodside Energy Limited. Most recently he was a technical and operations advisor to the department of industry, science and resources, the Commonwealth Government of Australia, on a range of offshore matters. He is a fellow of the Institution of Engineers Australia and has been a member of the Society of Petroleum Engineers since 1983.

Mr. Hamp holds a master of engineering degree from Imperial College, London (with first class honors). He has also attended executive training programs at Thunderbird International Business School, the University of Western Australia and the Australian Institute of Company Directors.

Daniel Murnane, Executive Vice President – General Counsel and Company Secretary

Mr. Murnane has served as our executive vice president – general counsel and company secretary since 2022.

Mr. Murnane has more than 16 years of experience gained in Australia and internationally, including over 12 years advising resources companies. He has worked as a senior associate in private legal practice predominately for energy companies on mergers and acquisitions, major projects, capital raisings and commercial disputes.

In addition, Mr. Murnane has held various in-house roles spanning legal and corporate governance environments, including with ASX and NYSE listed oil and gas companies.

Mr. Murnane is qualified as a solicitor in New South Wales and Papua New Guinea and holds a bachelor of arts degree and a bachelor of laws degree from the University of Canberra.

Board practices

Role and responsibilities

Our governing body is the board of directors. The board acts on behalf of shareholders and is accountable to shareholders for our overall direction and governance.

The role and responsibility of the board is to oversee and direct our senior management by:

- defining and monitoring our strategic direction;
- defining policies and procedures to ensure we operate within the legal, ethical and social requirements of our environment;
- establishing control and accountability systems within our operations to conform to the legal requirements and the expectations of shareholders and other stakeholders;
- defining and monitoring the management of an effective risk assessment strategy;
- securing funds to develop our assets;
- driving our performance.

Responsibility for our day-to-day management and administration is delegated by the board to the chief executive officer and managing director appointed by the board and other senior executives approved by the board. The delegation of authority is formally documented in our delegation of authority. Management is accountable to the board for the discharge of this delegated authority and for compliance with any limits on that authority.

The board met seventeen times during FY23 and nine times during TY23.

Board access to information and independent advice

All directors have the right to access company information. Our directors may seek independent professional advice at our expense where the director reasonably considers, after consulting with the chair, that obtaining independent advice is appropriate, and where the chair consents to the obtaining of that advice (with this consent not being unreasonably withheld).

Conflicts of interests

Directors must declare any conflict of interest that they may have at the start of all board meetings. Where a material personal interest arises with respect to a matter that is to be considered by the board, the director is required to declare that interest and must not take part in any board discussion or vote in relation to that matter, unless permitted in accordance with the Australian Corporations Act.

Independence

The board assesses the independence of each director, having regard to the ASX Corporate Governance Council's Principles and Recommendations 4th Edition, in light of information disclosed by each director to the board. Accordingly, when determining the independence of a non-executive director, the board considers whether the director:

- is, or has been, employed in an executive capacity by us or any of our subsidiaries and there has not been a period of at least three years between ceasing such employment and serving on the board;

- receives performance-based remuneration (including options or performance rights) from, or participates in an employee share incentive scheme;

- is, or has been within the last three years, in a material business relationship (e.g. as a supplier, professional adviser, consultant or customer) with us or any of our subsidiaries, or an officer of, or otherwise associated with, someone with such a relationship;

- is, represents, or has been within the last three years an officer or employee of, or professional adviser to, a substantial holder;

- has close personal ties with any person who falls within any of the categories described above; or

- has been a director of the entity for such a period that their independence from management and substantial holders may have been compromised.

In each case, the materiality of the interest, position, association or relationship is assessed by the board to determine whether it might interfere, or might reasonably be seen to interfere, with the director's capacity to bring an independent judgement to bear on issues before the board and to act in our best interests as a whole rather than in the interests of an individual security holder or other party.

Board committees, membership and charters

The board has the ability under our constitution to delegate its process and responsibilities to committees of the board. As of December 31, 2023 the board has established three standing committees to assist it in effectively exercising its responsibilities.

These are the:

- audit, risk and governance committee;

- people and culture committee; and

- sustainability and operational risk committee.

The board reviews the performance of the committees and considers whether new committees are required. During FY23, the board undertook a comprehensive review of the performance and charters of the board and its committees.

Audit, risk and governance committee

The role of the audit, risk and governance committee is to oversee the financial reporting process to seek to ensure the balance, transparency and integrity of published financial information, oversee risk identification and management and ensuring that we have the appropriate ethical standards and corporate governance policies and practices in place. The board has formally adopted an audit, risk and governance committee charter.

The responsibilities of the audit, risk and governance committee include:

Powers and functions

- improving the credibility and objectivity of our accountability processes (including financial reporting);

- engaging independent counsel and other advisers it seems necessary to carry out its duties;

- regularly assessing the need for an internal audit function and implement as required;

- ensuring the attendance of our officers at meetings as appropriate;

- being directly responsible for recommending to the board the appointment, compensation, retention and oversight of the work of the external auditor, including rotation of the external audit engagement partner; and

- recommending to the board all external audits and review engagement fees and terms as well as reviewing policies for the provision of non-audit services by the external auditor (and, when required, the framework for the pre-approval of such services).

Financial risk management and internal control

- leading our strategic direction in the management of material business risks (but excluding operational risks);
- working with the board and management to determine our risk tolerance;
- evaluating whether management is setting the appropriate control culture by communicating the importance of internal control and management of business risk;
- understanding the internal control systems implemented by management for the approval of transactions and the recording and processing of financial data; and
- understanding the controls and processes implemented by management to ensure that the financial statements derived from the underlying financial systems, comply with relevant Australian Accounting Standards and requirements, and are subject to appropriate management review.

Financial reporting

- gaining an understanding of the current areas of greatest financial risk and how these are being managed;
- reviewing significant accounting and reporting issues, including recent professional and regulatory pronouncements, and understanding their impact on financial reports;
- meeting with management and the external auditor to review financial statements, key accounting policies, judgements and decisions, and the results of the audit;
- providing a recommendation to the board as to whether our financial statements reflect the understanding of the committee members, and otherwise provide a true and fair view, of the financial position and our performance;
- obtaining from the chief executive officer and the chief financial officer, a written declaration under s 295A of the Corporations Act that:
    - o financial records have been properly maintained in accordance with the Corporations Act;
    - o written declarations have been received from senior management within each of our jurisdiction confirming tax compliance of financial statements within that jurisdiction;
    - o financial statements present a true and fair view, in all material respects, of our financial condition, operational results and are in accordance with relevant accounting standards; and
    - o there is an effective and efficient operation of our financial risk management and internal compliance and control system;
- reviewing the directors' report;
- reviewing the annual report; and
- reviewing the annual financial budget, including providing feedback on assumptions, objectives and fulfilling our strategic objectives.

Working with the external auditor

- reviewing the professional qualification of the external auditor (including background and experience of partner and auditing personnel);
- considering the independence of the external auditor and any potential conflicts of interest;
- reviewing on an annual basis the performance of the external auditor and making recommendations to the board for the appointment, reappointment or termination of the appointment of the external auditor;
- reviewing the external auditor's proposed audit scope and approach for the current year in light of our circumstances and changes in regulatory and other requirements;
- discussing with the external auditor any audit problems encountered in the normal course of audit work, including any restrictions on audit scope or access to information;
- ensuring that significant findings and recommendations made by the external auditor and management's proposed response are received, discussed and acted on appropriately;
- discussing with the external auditor the appropriateness of the accounting policies applied in our financial reports and whether they are considered to be aggressive, balanced or conservative; and
- reviewing policies for the provision of non-audit services by the external auditor and, where applicable, the framework for pre-approval of audit and non-audit services.

The audit, risk and governance committee reports to the board after each committee meeting and minutes of meetings are provided to all directors.

As of December 31, 2023, the audit, risk and governance committee consisted of the following three independent non-executive directors:

- Mr. Clark Davey (Chair of Committee);
- Mr. Peter Turnbull; and
- Mr. Peter Botten.

The audit, risk and governance committee met six times during FY23 and two times during TY23.

People and culture committee

The role of the people and culture committee is to oversee the following:

People and culture

- overseeing the development and implementation of employee performance and development programs and succession plans to attract, motivate and retain high quality people to enable appropriate skills, experience and the capability to deliver on our business strategy;
- overseeing our approach to culture and diversity;
- reviewing and monitoring employee engagement;
- reviewing on at least an annual basis, the measurable objectives for achieving gender diversity under the Diversity Policy and in accordance with the ASX Corporate Governance Council's Principles and Recommendations and assessing progress against the objectives; and
- monitoring the effective communication of the diversity policy and performance review policy.

Remuneration strategy, policies and structure

With respect to employees (excluding the chief executive officer and managing director in respect of whom such matters are reserved for the board), reviewing, monitoring and making recommendations to the board on the following:

- defining our remuneration policies and strategic objectives for remuneration frameworks to ensure they are informed by market practice, trends and legislative and regulatory requirements;

- assessing the separate policies and practices regarding remuneration of senior executives;

- our recruitment, retention and termination policies and procedures for senior executives;

- seeking external advice to ensure that employees are being rewarded with remuneration packages commensurate with their responsibilities and making recommendations to the board on any incentive scheme and any proposed changes;

- reporting on the progress against the long-term performance hurdles making recommendations on equity allocations, including outcomes of short-term objectives in line with company performance;

- recommendations from the chief executive officer and managing director relating to proposed merit increases for direct reports;

- overseeing fee frameworks, including superannuation arrangements for senior executives and other employees;

- identifying any changes to the senior executive remuneration policy;

- reviewing and recommending to the audit, risk and governance committee and the board the annual audited remuneration report for approval; and

- considering the outcome of the annual shareholder advisory vote on the adoption of the remuneration report and feedback of key stakeholders.

The people and culture committee reports to the board after each committee meeting and minutes of meetings are provided to all directors.

As of December 31, 2023, the people and culture committee consisted of the following three independent directors:

- Mr. Peter Turnbull (Chair of Committee);

- Mr. Peter Botten; and

- Mr. Clark Davey.

The people and culture committee met five times during FY23 and two times during TY23. For further information on management remuneration, please refer to the remuneration reports for TY23, FY23 and FY22, included elsewhere in this offering memorandum.

Sustainability and Operational Risk Committee

The sustainability and operational risk committee is responsible for:

Strategic direction

- leading our strategic direction in the management of material operational risks;
- working with the board and management to determine our operational risk tolerance;
- identifying opportunities to minimize the potential for harmful environmental or social impacts arising from our operations; and
- key policies and strategies in relation to the health and safety of our employees and the environmental and social impacts of our operations, including the:
  - o HSSE policy;
  - o risk management policy; and
  - o sustainability policy.

Oversight

- operational risk profile and risk management framework;
- implementation and review of operational risk management and internal compliance and control systems;
- management and identification of material exposure to operational, environmental and social sustainability risks and how those risks are managed;
- our OMS with a focus on HSSE issues; and
- our environmental and social programs.

Review

- on at least an annual basis, the effectiveness of our operational risk management framework in identifying and managing operational risks and controlling internal processes;
- management's plans for mitigation of material operational risks faced by us;
- the operational risk register on a periodic basis, identifying the main internal and external risk sources including material exposures to operational, environmental and social sustainability risks associated with our equity/participatory interests in oil and gas exploration, development and production projects and operations;
- our operational insurance program;
- our HSSE performance;
- any environmental or social impacts arising from our operations;

- compliance with our OMS and legislative and regulatory requirements with respect to HSSE and sustainability issues, including the requirements of approved environmental plans related to our operations; and

- our annual sustainability report, which includes our carbon emissions reporting, having regard to the recommendations of the financial stability board's taskforce on climate related financial disclosures.

Recommendations

- our operational risk tolerance and particular operational risks and/or risk management practices;

- continuous improvement of operational risk management and internal control processes, including any issues arising from reviews;

- our environmental and social programs; and

- external best practice developments and trends in relation to sustainability and operational, risk management policy and practice.

The sustainability and operational risk committee reports to the board after each committee meeting and minutes of meetings are provided to all directors.

As of December 31, 2023, the sustainability and operational risk committee consisted of the following four independent directors:

- Ms. Luciana Rachid (chair of committee);

- Mr. Peter Turnbull;

- Mr. Peter Botten; and

- Mr. Carlos Tadeu da Costa Fraga.

The sustainability and operational risk committee met four times during FY23 and two times during TY23.

Corporate governance

As a company listed on the ASX, we are required to comply with the Australian Corporations Act, the ASX Listing Rules and other Australian and international laws. The ASX Listing Rules require us to report on the extent to which we have followed the Corporate Governance Recommendations published by the ASX Corporate Governance Council in the fourth edition of the Corporate Governance Principles and Recommendations. We believe that throughout the FY23, TY23, and at the date of our last annual report (February 29, 2024), we have complied with all of these recommendations.

Compensation

For information on the compensation and share ownership of our directors and key management personnel in TY23, FY23 and FY22, please see the remuneration reports and Note 27 to our TY23 consolidated financial statements included elsewhere in this offering memorandum. We follow the principles of remuneration that are set out in the ASX Corporate Governance Council's Corporate Governance Principles and Recommendations. These include a policy of rewarding employees with a mixture of fixed, performance-linked and equity-based remuneration.

PRINCIPAL SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

Principal Shareholders

We are a public company listed on the ASX.

As of February 13, 2024, our largest shareholders are HSBC Custody Nominees (Australia) Limited, holding 29.06%, JP Morgan Nominees Australia Pty Limited, holding 19.39%, Citicorp Nominees Pty Limited, holding 14.26% and National Nominees Limited, holding 4.67% of our issued ordinary shares respectively.

We are not aware of any arrangements the operation of which may at a subsequent date result in a change of control of Karoon Energy.

Related Party Transactions

We enter into transactions with certain related parties or our affiliates from time to time and in the ordinary course of our business. We believe these agreements are on terms no more favorable to the related parties or our affiliates than they would expect to negotiate with disinterested third parties, unless otherwise stated.

From time to time, we provide accounting, administrative and technical services to subsidiaries at cost or at cost plus a mark-up where required under relevant tax transfer pricing legislation. We also provide funding to our overseas subsidiaries via an increase in contributed equity and intercompany loans to Australian subsidiaries. Intercompany loans are provided at a nil % interest rate and no fixed term for repayment. These transactions are eliminated when we consolidate our financial statements.

For a discussion of related party transactions, see Note 27 to our consolidated financial statements for TY23, included elsewhere in this offering memorandum.

DESCRIPTION OF OTHER FINANCING ARRANGEMENTS

Below is a summary of our other material borrowings that will remain outstanding as of the date of this offering memorandum. This summary does not purport to be complete and is subject to, and qualified in its entirety by reference to, the underlying documents.

Reserve Based Lending Facility

Overview

On November 16, 2023, we entered into a senior secured syndicated facility agreement with, among others, Deutsche Bank AG, Sydney Branch, ING Belgium SA/NV, Macquarie Bank Limited and Shell Western Supply and Trading Limited, as original lenders, Global Loan Agency Services Australia Pty Ltd as agent and Citibank, N.A., London Branch, as offshore security agent.

The syndicated facility provides for a U.S. dollar-denominated revolving credit facility with commitments totaling US$340 million, which will be reduced in accordance with the reduction schedule described below (the "Initial Facility"). We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340 million committed under the RBL facility will become available, subject to customary conditions to draw. Subject to satisfying certain conditions, we have the option of increasing the commitments under the syndicated facility by up to US$200 million through the establishment of accordion facilities (each an "Accordion Facility" and, together with the Initial Facility, the "RBL facility").

Borrowing Base Limit

The maximum amount that may be drawn and outstanding under the RBL facility is equal to the lesser of the total commitments and a borrowing base limit, which is redetermined as at each March 31 and September 30, commencing March 31, 2024. The borrowing base limit is the lesser of (a) the sum of capital expenditure addback value and the net present value of the forecast cashflow available for debt service of the borrowing base assets over their field life divided by 1.5 and (b) the sum of capital expenditure addback value and the net present value of the forecast cashflow available for debt service of the borrowing base assets over the RBL facility life divided by 1.3. The capex addback value is the lower of (i) the present value of the forecast capital expenditure in respect of the borrowing base assets for the 12-month period from the relevant redetermination date and (ii) the sum of each available facility, cash and cash equivalent investment and other permitted available funding sources that are committed and reasonably anticipated to be available to fund such capital expenditure. There may also be interim redeterminations of the borrowing base limit in certain circumstances. Loan drawdowns are also subject to customary conditions precedent.

The initial borrowing base assets consisted of our net working interest in the Baúna and Patola fields (BM-S-40) and Neon field (S-M-1037 and S-M-1102). The RBL facility provides for additional assets to be designated as borrowing base assets upon satisfaction of various conditions (including majority lender approval), and we are required to request that the Who Dat Assets are included as borrowing base assets as soon as reasonably practicable following their acquisition. We are currently in the process of incorporating our interest in the Who Dat oil and gas fields into our borrowing base assets, and we expect this process to complete by June 30, 2024, although there can be no assurance as to whether the RBL facility lenders will accept the Who Dat assets as a borrowing base asset or the timing for such designation. In certain circumstances, we may also de-designate petroleum assets such that they cease to be borrowing base assets.

We may use amounts borrowed under the Initial Facility for general corporate purposes (other than for the purpose of paying a dividend). An Accordion Facility may be used for the purposes agreed with the applicable Accordion Facility lenders.

Borrowers and guarantors

KEI (Brazil Santos) Pty Ltd, Karoon Petróleo e Gás Ltda ("KPG") and KEI Finance 1 Pty Ltd are the original borrowers under the RBL facility and they also guarantee each other borrower's obligations (the "Original Borrowing Base Obligors" and, together with any other person which becomes a borrower under the RBL facility or which is or becomes a guarantor under the RBL facility and directly owns our interest in a Borrowing Base Asset, the "Borrowing Base Obligors"). The borrowers' obligations under the RBL facility are also guaranteed by the Parent Guarantor and Karoon Energy International Pty Ltd (the "Original Corporate Guarantors" and, together with any other person which becomes a guarantor under the RBL facility, the "Corporate Guarantors", and the Corporate Guarantors and the Borrowing Base Obligors, collectively, the "Obligors"). The Issuer, KUSA Inc. and A.C.N. 672 679 793 Pty. Ltd. will become Corporate Guarantors on or before the issuance of the Notes. The guarantors under the RBL facility (including the Borrowing Base Obligors) will also be guarantors of the Notes. Subject to certain conditions, we may add or retire borrowers and guarantors under the RBL facility. Such additional borrowers shall become Borrowing Base Obligors and such additional guarantors shall become Borrowing Base Obligors if they directly own the Group's interest in a borrowing base asset. For the avoidance of doubt, a Corporate Guarantor will become a Borrowing Base Obligor (and cease to be a Corporate Guarantor) if it subsequently becomes a borrower under the RBL facility or the direct owner of the Group's interest in the borrowing base assets. Subject to certain exceptions and agreed security principles, we are required to ensure that the obligors account for at least 90% of EBITDAX of the Group and 90% of total assets of the Group on each June 30 and December 31 (each a "Reporting Date"), commencing on June 30, 2024. The RBL facility contains agreed security principles that govern the terms on which security and guarantees are provided (including the scope of the collateral) to facilitate the negotiation of future individual security documents and the joinder of future borrowers and guarantors (the "security principles").

Term

The Initial Facility matures on the earlier of (i) September 30, 2028 and (ii) the date by which the aggregate remaining 2P reserves of the borrowing base assets will be equal to or less than 25% of the borrowing base asset 2P reserves as of the closing of the Initial Facility. The maturity of an Accordion Facility will be the date agreed with the applicable Accordion Facility lenders provided that it may not be earlier than the maturity of the Initial Facility.

Reduction and Repayment

The total committed facility amount under the Initial Facility reduces in accordance with the following amortization schedule:

	Total committed facility amount
Initial Facility closing date	US$340,000,000
March 31, 2026	US$283,333,333
September 30, 2026	US$226,666,667
March 31, 2027	US$170,000,000
September 30, 2027	US$113,333,333
March 31, 2028	US$56,666,667
September 30, 2028	US$nil

The amortization schedule for an Accordion Facility (if any) will be as agreed with the relevant Accordion Facility lenders, provided that the weighted average life may not be shorter than that applicable to the Initial Facility.

Voluntary Prepayment and Cancellation

Subject to minimum quantitative thresholds and payment of break costs (if any), we may, at any time (by giving three business days' notice) cancel and/or prepay the whole or any part of the available aggregate facility at that time. Subject to certain conditions and exceptions, any amounts prepaid or repaid may be reborrowed while any amounts that are canceled may not be reinstated.

Mandatory Prepayment and Review Events

Change of operator

We may be required to prepay the lenders if KPG ceases to be the operator of the Baúna and Patola fields (BM-S-40) or if we cease to own at least 50% of the aggregate net working interests in the Baúna and Patola fields (BM-S-40).

Disposal and insurance proceeds

Subject to certain customary exclusions, thresholds and reinvestment rights, we are required to prepay loans and cancel available commitments using the net cash proceeds from any permitted disposals of borrowing base assets or insurance claims relating to the borrowing base assets to the extent required to ensure that the outstanding RBL facility amount does not exceed the then-applicable borrowing base limit (determined after taking into account the relevant disposal or insurance event).

Borrowing Base Deficiency

We will also be required to prepay any amounts borrowed under the RBL facility that exceed the borrowing base limit on any borrowing base redetermination date. Such repayments must be made within 60 days of the relevant borrowing base redetermination date (or, if later, 60 days after the adoption of the relevant banking case showing that a borrowing base deficiency exists).

Review events

Review events under the RBL facility include a change of control, the delisting of the Parent Guarantor from the ASX, a suspension of the Parent Guarantor's shares from trading on the ASX for a continuous period of 10 business days (other than for certain imminent transaction announcements) or the unanticipated cessation of production for at least 90 continuous days, termination or cancellation of certain material contracts or governmental authorization or governmental intervention in the borrowing base assets. Following the occurrence of a review event, we may agree with the lenders to amend the RBL facility. If we and the lenders cannot agree to a basis on which the facility will continue, we may be required to pay all or a part of the amounts outstanding under the RBL facility.

Interest and Fees

The interest rate on loans under the RBL facility is calculated by reference to a margin over SOFR plus a credit adjustment spread. The margin applicable to Initial Facility loans is 4.00% per annum.

We must pay a commitment fee with respect to the Initial Facility equal to 40% of the margin on the undrawn Initial Facility commitment (other than the portion (if any) exceeding the borrowing base limit); and 20% of the margin on the portion (if any) of the undrawn Initial Facility commitment exceeding the borrowing base limit.

We are required to pay letter of credit fees and any applicable issuance fees and costs as agreed with the applicable issuing bank in relation to any letters of credit issued under the RBL facility.

The margin, any commitment fees and any establishment or similar fees applicable to an Accordion Facility will be as agreed with the relevant lenders.

Guarantee and Security

The RBL facility is secured on a senior secured basis by the following assets and security, subject to customary exceptions and the security principles:

(a) the shares or other equity ownership interests in the Borrowing Base Obligors, the material borrowing base assets of the Borrowing Base Obligors (including bank accounts, material contracts, insurance policies, hedging policies and intra-group loans) and an all-assets general security deed or equivalent composite security over the assets of the Borrowing Base Obligors incorporated in Australia; and

(b) the shares or other equity ownership interests in the Corporate Guarantors (other than the Parent Guarantor) and, an all-assets general security deed or equivalent composite security over the assets of the Corporate Guarantors.

The security documents are governed by Australian, Brazilian or English law, as applicable. Further U.S. law security will be entered into as part of the designation of the Issuer and KUSA Inc. as Corporate Guarantors and the subsequent designation of KUSA Inc. as a Borrowing Base Obligor upon the designation of the Who Dat asset as borrowing base assets under the RBL facility.

The RBL facility includes customary further assurance obligations, subject to the security principles, for the creation of additional security by existing and future Borrowing Base Obligors and Corporate Guarantors.

The Notes will be secured on a second lien basis (subject to the security principles and applicable local law) over the same assets as the RBL facility.

Covenants and Undertakings

Financial Covenants – Borrowing Base Obligors

The RBL facility contains the following financial covenants in relation to the Borrowing Base Obligors:

(a) Debt service cover ratio (being the trailing twelve month ratio of cashflow available for debt service to debt service) of not less than 1.10 times as of each Reporting Date and 1.20 times as of any three consecutive Reporting Dates.

(b) Forecast 12-month liquidity ratio (being the 12-month forecast ratio of total funding sources to total funding uses) of at least 1.10 times as of each borrowing base limit redetermination date.

(c) Minimum cash balance of US$20,000,000 (or its equivalent in other currencies) as of the last business day of each calendar month.

We are permitted to cure a failure to comply with the above financial covenants by repaying debt (in the case of the debt service cover ratio) which will be counted as cashflow available for debt service or contributing cash and cash equivalents to the Borrowing Base Obligors (in the case of the liquidity ratio or minimum cash balance).

Financial Covenant – Group

We are required to ensure that the leverage ratio (the ratio of net debt of the Group to EBITDAX of the Group) is not greater than 3.25 times as of each Reporting Date. Net debt is calculated as debt less cash and cash equivalents as shown on our financial statements.

We are permitted to cure a failure to comply with the leverage ratio by procuring an equity contribution which will be counted as EBITDAX.

The following table sets out the relevant financial ratios as calculated using the financial covenant calculations documented in the syndicated facility agreement as of December 31, 2023.

	Covenant level	Level as of December 31, 2023
Financial covenants		
Debt service cover ratio	No less than 1.1x	9.8x
Liquidity ratio	At least 1.1x	1.41x
Minimum cash balance	Greater than US$20.0 million	US$139.6 million
Net leverage ratio	Not greater than 3.25x	0.2x

General Covenants – Obligors

The RBL facility includes certain customary undertakings imposing obligations and restricting operations and the ability for any Obligor to take certain actions, subject to certain agreed exceptions and qualifications. The RBL facility also includes restrictions on the Obligors, subject to certain agreed exceptions and qualifications, including but not limited to (i) creating security interests; (ii) conduct of business; (iii) disposing of assets or entering into merger transactions; (iv) incurring additional debt; (v) granting guarantees and indemnities; and (vi) issuance of further shares.

General Covenants – Borrowing Base Obligors

In addition to the above, the RBL facility includes certain undertakings imposing obligations and restricting operations and the ability for any Borrowing Base Obligor to take certain actions, including but not limited to: (i) hedging arrangements; (ii) incurrence of debt and issue guarantees; (iii) maintenance of borrowing base assets (including performance under field documents); (iv) entering into, amending or terminating field documents; (v) acquisitions; (vi) distributions (including requiring the approval of the majority of the lenders under the RBL facility if the proportion of the borrowing base limit under the RBL facility attributable to development assets exceeds 35% of the total borrowing base limit); (vii) entering into joint venture arrangements; (viii) compliance with environmental laws; (ix) ensuring not less than 75% of net entitlements to production from the borrowing base assets are subject to acceptable offtake arrangements; and (x) amendments to other debt documents.

Hedging

Under our RBL facility, we are required to enter into hedging arrangements to mitigate our exposure to movements in oil prices by reference to a minimum proportion of our forecast production from Baúna on a rolling two-year basis. If we establish an Accordion Facility, our hedging obligation will be calculated by reference to a minimum proportion of our forecast production from the borrowing base assets instead. Our hedging requirements are re-assessed 60 days after the date of each loan and Accordion Facility loan and every six months thereafter. The amount we are required to hedge is determined by our collateral coverage ratio at each testing date, which is calculated by reference to the value of Baúna or our borrowing base assets, as applicable, and the amount we have drawn down under the facility. We are prohibited from hedging more than 70% of our forecast production under our RBL facility. The table below sets forth our minimum hedging requirements over the following 6, 12, 18 and 24 months as determined by reference to our collateral coverage ratio as of each testing date.

	Forecast production over the next			
	6 months	12 months	18 months	24 months
Collateral coverage ratio as of each testing date				
Less than or equal to 1.25x	40.0%	30.0%	23.0%	17.0%
Greater than 1.25x and less than or equal to 1.67x	30.0%	23.0%	17.0%	–
Greater than 1.67x and less than or equal to 2.5x	23.0%	17.0%	–	–
Greater than 2.5x and less than or equal to 5.0x	17.0%	–	–	–
Greater than 5.0x	–	–	–	–

Events of Default

The RBL facility includes customary events of default for facilities of its type, which are subject to customary grace periods, thresholds and other qualifications.

The occurrence of an event of default under the RBL facility would allow the lenders (if a two-thirds majority of lenders so direct) to cancel their commitments and/or declare that all or part of the loans, together with accrued interest and other amounts outstanding:

- are immediately due and payable;
- payable immediately on demand;
- declare that full cash cover in respect of each letter of credit is immediately due and payable;
- declare that cash cover in respect of each letter of credit is payable on demand; and/or
- direct the security agent to exercise any rights available under the finance documents.

Governing Law and Jurisdiction

The RBL facility is governed by English law.

DESCRIPTION OF THE NOTES

General

Karoon USA Finance Inc, a Delaware corporation (the "Issuer"), will issue US$350.0 million aggregate principal amount of 10.500% Second-Priority Senior Secured Notes due 2029 (the "Notes"). The Notes will be issued under an indenture, to be entered into by and among the Issuer, Karoon Energy Limited (the "Parent Guarantor"), the Subsidiary Guarantors (as defined below) and GLAS Trust Company LLC, as Trustee, in a private transaction that is not subject to the registration requirements of the Securities Act. See "Notice to Investors." The indenture will not be subject to the provisions of the Trust Indenture Act of 1939, as amended (the "TIA"). Consequently the holders of the Notes generally will not be entitled to the protections provided under the TIA to holders of Notes issued under a qualified indenture.

The following summary of certain provisions of the indenture, the Notes, the Security Documents, the Senior Lien Intercreditor Documents and the Second Lien Pari Passu Intercreditor Agreement does not purport to be complete and is subject to, and is qualified in its entirety by reference to, all the provisions of those agreements, including the definitions of certain terms therein. We urge you to read the indenture, the Security Documents, the Senior Lien Intercreditor Documents and the Second Lien Pari Passu Intercreditor Agreement because they, and not this description, define your rights as holders of Notes. Copies of the indenture, the Security Documents, the Senior Lien Intercreditor Documents and the Second Lien Pari Passu Intercreditor Agreement may be obtained from the Issuer upon request. Capitalized terms used in this "Description of the Notes" section and not otherwise defined have the meanings set forth in the section "—Certain Definitions."

Following the Issue Date, the Issuer may issue additional notes under the indenture from time to time. Any issuance of additional notes is subject to the covenants described below under the caption "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" and "—Certain Covenants—Liens." The Notes and any additional notes subsequently issued under the indenture may, at our election, be treated as a single class as the applicable series of notes for all purposes under the indenture, including, without limitation, waivers, amendments, redemptions and offers to purchase; provided that if the additional notes are not fungible with the existing Notes for U.S. federal income tax or other purposes, such additional notes will have a separate CUSIP number, if applicable. Unless the context otherwise requires, for all purposes of the indenture and this "Description of the Notes," references to the Notes include any additional notes of such series actually issued.

Principal of, premium, if any, and interest on the Notes will be payable, and the Notes may be exchanged or transferred, at the office or agency designated by the Issuer (which initially shall be the designated office or agency of the Trustee).

The Notes will be issued only in fully registered form, without coupons, in minimum denominations of US$200,000 and in integral multiples of US$1,000 in excess thereof; provided that Notes may be issued in denominations of less than US$200,000 solely to accommodate book-entry positions that have been created by a DTC participant in denominations of less than US$200,000. No service charge will be made for any registration of transfer or exchange of Notes, but the Issuer may require payment of a sum sufficient to cover any transfer tax or other similar governmental charge payable in connection therewith.

Interest on the Notes will accrue from the Issue Date or, if interest has already been paid, from the date it was most recently paid. Interest will be computed on the basis of a 360-day year comprised of 12 30-day months.

Terms of the Notes

The Notes will be senior obligations of the Issuer and will be secured only by the second-priority security interests in the Collateral described below under "—Security." The Notes will mature on May 14, 2029. Interest on the Notes will accrue at a rate of 10.500% per annum from the Issue Date or from the most recent date to which interest has been paid or provided for. Interest on the Notes will be payable semiannually to holders of record at the close of business on or immediately preceding the interest payment date on May 14 and November 14 of each year, commencing on November 14, 2024.

The Issuer intends to apply for the listing and quotation of the Notes to the Singapore Exchange Securities Trading Limited (the "SGX-ST") for the Notes to be admitted to the Official List of the SGX-ST. See "—Listing." Upon any issuance of definitive notes, the Issuer will appoint and maintain a paying agent in Singapore for so long as the Notes are listed on the SGX-ST and the rules of such exchange so require. In such event, an announcement shall be made through the SGX-ST and will include all material information with respect to the delivery of the definitive notes, including details of the paying agent in Singapore.

Optional Redemption

On or after May 14, 2026, the Issuer may redeem the Notes at its option, in whole at any time or in part from time to time, upon not less than 10 nor more than 30 days' prior notice mailed by first class mail to each holder's registered address or delivered electronically if held by DTC, at the following redemption prices (expressed as a percentage of principal amount), plus accrued and unpaid interest and additional interest, if any, to, but excluding, the redemption date (subject to the right of holders of record of such series on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the 12-month period commencing on May 14 of the years set forth below:

Period	Redemption Price
2026	105.250%
2027	102.625%
2028 and thereafter	100.000%

In addition, prior to May 14, 2026, the Issuer may redeem the Notes at its option, in whole at any time or in part from time to time, upon not less than 10 nor more than 30 days' prior notice mailed by the Issuer by first class mail to each holder's registered address, or delivered electronically if held by DTC, at a redemption price equal to 100% of the principal amount of the Notes redeemed *plus* the Applicable Premium as of, and accrued and unpaid interest and additional interest, if any, to, but excluding, the applicable redemption date (subject to the right of holders of record of such series on the relevant record date to receive interest due on the relevant interest payment date).

In addition, at any time prior to May 14, 2026 but not more than once during each consecutive 12-month period commencing with the Issue Date, the Issuer may redeem up to 10% of the aggregate principal amount of the Notes originally issued under the indenture at its option at a redemption price equal to 103% of the principal amount of the Notes being redeemed, plus accrued and unpaid interest, if any, to but excluding the redemption date.

Notwithstanding the foregoing, at any time and from time to time on or prior to May 14, 2026, the Issuer may redeem in the aggregate up to 40% of the aggregate principal amount of the Notes originally issued under the indenture (calculated after giving effect to any issuance of additional notes) with an amount of cash not greater than the net cash proceeds of one or more Equity Offerings by the Parent Guarantor or any of its subsidiaries to the extent the net cash proceeds thereof are contributed to the common equity capital of the Issuer or used to purchase Capital Stock (other than Disqualified Stock) of the Issuer, at a redemption price (expressed as a percentage of the principal amount thereof) of 110.500%, plus accrued and unpaid interest and additional interest, if any, to the redemption date;

provided, that such redemption shall occur within 180 days after the date on which any such Equity Offering is consummated upon not less than 10 nor more than 30 days' notice mailed by the Issuer to each holder of Notes being redeemed, or delivered electronically if held by DTC, and at least 60% in aggregate principal amount of Notes originally issued under the indenture (calculated after giving effect to any issuance of additional notes) remains outstanding immediately after the occurrence of such redemption and such redemption otherwise occurs in accordance with the procedures set forth in the indenture.

All redemptions of the Notes will be made upon not less than 10 days' nor more than 30 days' prior notice, except that a redemption notice may be made more than 30 days prior to a redemption date if the notice is issued in connection with a defeasance of the Notes or a satisfaction and discharge of the indenture. Notice of any redemption upon any corporate transaction or other event (including any Equity Offering, incurrence of Indebtedness, Change of Control, Asset Sale or other transaction) may be given prior to the completion thereof. In addition, any redemption described above or notice thereof may, at the Issuer's discretion, be subject to one or more conditions precedent, including, but not limited to, completion or occurrence of the corporate transaction or other event. In addition, if such redemption is subject to satisfaction of one or more conditions precedent, such notice will describe each such condition, and if applicable, will state that, in the Issuer's discretion, the redemption date may be delayed until such time as any or all such conditions are satisfied (or waived by the Issuer in its sole discretion), or that such redemption may not occur and such notice may be rescinded in the event that any or all such conditions are not satisfied (or waived by the Issuer in its sole discretion) by the redemption date, or by the redemption date as so delayed, or that such notice may be rescinded at any time in Issuer's discretion if in the good faith judgment of the Issuer any or all of such conditions will not be satisfied. If any such condition precedent has not been satisfied, the Issuer will provide written notice to the Trustee not less than two Business Days prior to the redemption date that such condition precedent has not been satisfied, and that either the notice of redemption is rescinded and the redemption subject to the satisfaction of such condition precedent shall not occur or, at the Issuer's discretion, the redemption date is delayed until such time as such condition precedent has been satisfied. If the Issuer does not provide any such notice by the date that is two Business Days prior to the applicable redemption date, the redemption shall become unconditional, and the Issuer shall be required to redeem the Notes.

The Issuer may redeem Notes pursuant to one or more of the relevant provisions in the indenture, and a single notice of redemption may be delivered with respect to redemptions made pursuant to different provisions. Any such notice may provide that redemptions made pursuant to different provisions will have different redemption dates. The Trustee shall promptly send or make available a copy of such notice to the holders of the Notes. In addition, the Issuer may provide in such notice that payment of the redemption price and performance of the Issuer's obligations with respect to such redemption may be performed by another Person; provided, however, that the Issuer will remain obligated to pay the redemption price and perform its obligations with respect to such redemption in the event such other Person fails to do so.

If holders of not less than 90% in aggregate principal amount of the outstanding Notes validly tender and do not withdraw such Notes in any tender offer or other redemption (including in connection with an Equity Offering, incurrence of Indebtedness, Change of Control, Asset Sale or other transaction) and the Issuer, or any third party making such an offer in lieu of the Issuer, purchases all of the Notes validly tendered and not withdrawn by such holders, the Issuer or such third party will have the right, upon not less than 10 nor more than 30 days' prior written notice, given not more than 30 days following such purchase pursuant to the redemption described above, to redeem all Notes that remain outstanding following such purchase at a price in cash equal to the price offered to each other holder in such tender offer (which may be less than par and shall exclude any early tender premium or similar premium and any accrued and unpaid interest paid to any holder in such tender offer payment) plus, to the extent not included in the tender offer payment, accrued and unpaid interest, if any, thereon, to, but excluding the date of redemption or purchase date, subject to the right of holders of record of the Notes on the relevant record date to receive interest due on the relevant interest payment date falling on or prior to the date of redemption or purchase date.

Additional Amounts

All payments made by or on behalf of the Issuer under or with respect to the Notes or any of the Guarantors with respect to any Guarantee will be made free and clear of and without withholding or deduction for, or on account of, any present or future Taxes unless the withholding or deduction for, or on account of, such Taxes is then required by law. If any deduction or withholding for, or on account of, any Taxes imposed or levied by or on behalf of any Tax Jurisdiction will at any time be required to be made from any payments made by the Issuer under or with respect to the Notes or any of the Guarantors with respect to any Guarantee, including payments of principal, redemption price, purchase price, interest or premium, the Issuer or the relevant Guarantor, as applicable, will pay such additional amounts (the "Additional Amounts") as may be necessary in order that the net amounts received in respect of such payments by each holder after such withholding or deduction (including any such withholding or deduction from such Additional Amounts) will equal the respective amounts that would have been received in respect of such payments in the absence of such withholding or deduction; provided, that no Additional Amounts will be payable with respect to:

(a) any Taxes, to the extent such Taxes would not have been imposed but for the existence of any present or former connection between the holder (or between a fiduciary, settler, beneficiary, member or shareholder of, or possessor of a power over, the relevant holder, if the relevant holder is an estate, nominee, trust, partnership, limited liability company or corporation) or the beneficial owner of the Notes and the relevant Tax Jurisdiction (including, without limitation, being a resident of such jurisdiction or having a permanent establishment in such jurisdiction for Tax purposes), other than the mere holding of such note, the enforcement of rights under such note or the receipt of any payments in respect of such note;

(b) any Taxes, to the extent such Taxes were imposed as a result of the presentation of a note for payment (where presentation is required) more than 30 days after the relevant payment is first made available for payment to the holder (except to the extent that the holder would have been entitled to Additional Amounts had the note been presented for payment on the last day of such 30-day period);

(c) any estate, inheritance, gift, value added, sales, use, excise, transfer, personal property or similar Taxes;

(d) Taxes imposed on or with respect to a payment made to a holder or beneficial owner of Notes who would have been able to avoid such withholding or deduction by presenting the relevant Notes to another paying agent appointed by the Issuer in accordance with the indenture;

(e) any Taxes payable other than by deduction or withholding from payments under, or with respect to, the Notes or with respect to any Guarantee;

(f) any Taxes, to the extent such Taxes are imposed, withheld or deducted by reason of the failure of the holder or beneficial owner of Notes or any payment in respect of such note to comply with any reasonable written request of the Issuer or the relevant Guarantor, addressed to the holder and made at least 30 days before any such withholding or deduction is to be made, to satisfy any certification, identification, information or other reporting requirements, provided that such compliance is required by statute, treaty, regulation or administrative practice of a Tax Jurisdiction, as a precondition to exemption from, or reduction in the rate of deduction or withholding of, Taxes imposed by the Tax Jurisdiction (including, without limitation, a certification that the holder or beneficial owner is not resident in the Tax Jurisdiction), but in each case, only to the extent the holder or beneficial owner is legally entitled to satisfy such requirement;

(g) where such withholding or deduction is required as a result or by reason of a failure of the holder or beneficial owner of Notes to quote a tax file number, an Australian Business Number or proof of some other exemption;

(h) any Taxes imposed or withheld pursuant to Sections 1471 through 1474 of the Code as of the Issue Date (or any amended or successor version of such sections), any current or future regulations promulgated thereunder, any official interpretations thereof, any similar law or regulation adopted pursuant to an intergovernmental agreement between a non-U.S. jurisdiction and the United States with respect to the foregoing (or any fiscal or regulatory legislation, rules or practices implementing such an intergovernmental agreement) or any agreements entered into pursuant to Section 1471(b)(1) of the Code;

(i) any Tax that is imposed on or with respect to any payment made to any holder who is a fiduciary or partnership or an entity that is not the sole beneficial owner of such payment, to the extent that a beneficiary or settlor (for tax purposes) with respect to such fiduciary, a member of such partnership or the beneficial owner of such payment would not have been entitled to the Additional Amounts had such beneficiary, settlor, member or beneficial owner been the actual holder of the applicable note; or

(j) any combination of items (a) through (i) above.

In addition to the foregoing, the Issuer and the Guarantors will also pay and indemnify the Trustee and holders for any present or future stamp, issue, registration, court or documentary taxes, or any other excise or property taxes, charges or similar levies (including penalties, interest and any other reasonable expenses related thereto) that are levied by any Tax Jurisdiction on the execution, delivery, issuance, enforcement or registration of any of the Notes, the indenture or any Guarantee or any other document referred to therein, except for any such Taxes imposed or levied as a result of a transfer after the Issue Date.

If the Issuer or any Guarantor, as the case may be, becomes aware that it will be obligated to pay Additional Amounts with respect to any payment under or with respect to the Notes or Guarantee, the Issuer or the relevant Guarantor, as the case may be, will deliver to the Trustee on a date that is at least 30 days prior to the date of that payment (unless the obligation to pay Additional Amounts arises less than 30 days prior to that payment date, in which case the Issuer or the relevant Guarantor shall notify a Trust Officer of the Trustee promptly thereafter) an Officers' Certificate stating the fact that Additional Amounts will be payable and the amount estimated to be so payable. The Officers' Certificate must also set forth any other information reasonably necessary to enable any Paying Agent to pay Additional Amounts to holders on the relevant payment date. The Trustee and Paying Agents shall be entitled to rely solely on such Officers' Certificate as conclusive proof that such payments are necessary.

The Issuer or the relevant Guarantor will make all withholdings and deductions for, or on account of, Taxes required by law and will remit the full amount deducted or withheld to the relevant Tax authority in accordance with applicable law. The Issuer or the relevant Guarantor will use its reasonable efforts to obtain Tax receipts from each Tax authority evidencing the payment of any Taxes so deducted or withheld. The Issuer or the relevant Guarantor will furnish to the Trustee (or to a holder upon written request), within a reasonable time after the date the payment of any Taxes so deducted or withheld is made, certified copies of Tax receipts evidencing payment by the Issuer or the Guarantor, as the case may be, or if, notwithstanding such entity's efforts to obtain receipts, receipts are not obtained, other evidence of payments (reasonably satisfactory to the Trustee) by such entity.

Whenever in the indenture or in this "Description of the Notes" there is mentioned, in any context, the payment of amounts based upon the principal amount of the Notes or of principal, interest or any other amount payable under, or with respect to, any of the Notes or any Guarantee, such mention shall be deemed to include mention of the payment of Additional Amounts to the extent that, in such context, Additional Amounts are, were or would be payable in respect thereof.

The above obligations will survive any termination, defeasance or discharge of the indenture or any transfer by a holder or beneficial owner of its Notes, and will apply, *mutatis mutandis*, to any jurisdiction in which any successor Person to the Issuer or any Guarantor is incorporated, organized or resident for Tax purposes or any political subdivision thereof or therein or any jurisdiction from or through which such Person makes any payment on the Notes (or any Guarantee) or any political subdivision thereof or therein.

Tax Redemption

The Issuer may redeem the Notes, in whole but not in part, at its discretion at any time upon giving not less than 10 nor more than 30 days' prior notice to the holders of the Notes (with a copy to the Trustee and paying agent) (which notice will be irrevocable and given in accordance with the procedures described in "—Selection of Notes to be Redeemed; Notes Redeemed in Part"), at a redemption price equal to 100% of the aggregate principal amount thereof, together with accrued and unpaid interest, if any, to the date fixed by the Issuer for redemption (a "Tax Redemption Date") and all Additional Amounts (if any) then due and which will become due on the Tax Redemption Date as a result of the redemption or otherwise (subject to the right of holders of the Notes on the relevant record date to receive interest due on an interest payment date that is on or prior to the Tax Redemption Date and Additional Amounts (if any) in respect thereof), if on the next date on which any amount would be payable in respect of the Notes, the Issuer or a Guarantor is or would be required to pay Additional Amounts and (a) the Issuer or Guarantor cannot avoid any such payment obligation by taking reasonable measures available to it and (b) the requirement arises as a result of:

(a) any amendment to, or change in, the laws or treaties (or any protocols, regulations or rulings promulgated thereunder) of a relevant Tax Jurisdiction which change or amendment is announced and becomes effective on or after the Issue Date (or, if the applicable Tax Jurisdiction became a Tax Jurisdiction on a date after the Issue Date, such later date); or

(b) any amendment to, or change in, an official position, or the introduction of an official position, regarding the interpretation, administration or application of such protocols, laws, regulations, treaties or rulings (including by virtue of a holding, judgment or order by a court of competent jurisdiction or a change in published administrative practice) which amendment, change or introduction is announced and becomes effective on or after the Issue Date (or, if the applicable Tax Jurisdiction became a Tax Jurisdiction on a date after the Issue Date, such later date).

The Issuer will not give any such notice of redemption earlier than 30 days prior to the earliest date on which the Issuer or Guarantor would be obligated to make such payment or withholding if a payment in respect of the Notes or Guarantees was then due, and the obligation to pay Additional Amounts must be in effect at the time such notice is given. Prior to the publication or provision of any notice of redemption of the Notes pursuant to the foregoing, the Issuer will deliver to the Trustee an opinion of independent Tax counsel of recognized standing in the relevant Tax Jurisdiction, to the effect that there has been such amendment or change or introduction that would entitle the Issuer to redeem the Notes hereunder. In addition, before the Issuer publishes or provides notice of redemption of the Notes as described above, it will deliver to the Trustee an Officers' Certificate to the effect that the obligation to pay Additional Amounts cannot be avoided by the Issuer or Guarantor taking commercially reasonable measures available to it.

The Trustee will accept and shall be entitled to rely on such Officers' Certificate and opinion of counsel as sufficient evidence, without further inquiry, of the existence and satisfaction of the conditions precedent as described above, in which event it will be conclusive and binding on the holders of the notes.

Mandatory Redemption

The Issuer is not required to make mandatory redemption or sinking fund payments with respect to the Notes. However, under certain circumstances, the Issuer may be required to offer to purchase the Notes as described under the caption "—Offers to Purchase; Open Market Purchases."

Offers to Purchase; Open Market Purchases

Under certain circumstances, the Issuer may be required to offer to purchase Notes as described under the captions "—Change of Control" and "—Certain Covenants—Asset Sales." We may at any time and from time to time purchase Notes in the open market or otherwise.

Selection of Notes to be Redeemed; Notes Redeemed in Part

In the case of any partial redemption, selection of Notes of the applicable series for redemption will be made by the Trustee in compliance with the requirements of the SGX-ST, for so long as the Notes are listed on such exchange (and the Issuer shall notify a Trust Officer of the Trustee in writing of any such change in listing), or if such Notes are not so listed, on a pro rata basis to the extent practicable or by lot or by such other method as the Trustee shall deem fair and appropriate (and, in each case, in such manner that complies with the requirements of DTC, if applicable); provided that no Notes of US$200,000 or less shall be redeemed in part. The Trustee shall make the selection from outstanding Notes not previously called for redemption. Upon selection, the Trustee will notify the Issuer promptly of the Notes or portions of Notes to be redeemed. Notices of redemption will be mailed by first class mail (or delivered electronically if held by DTC) at least 10 but not more than 30 days before the redemption date to each holder of Notes to be redeemed at its registered address, except that redemption notices may be sent more than 30 days prior to a redemption date if the notice is issued in connection with a defeasance of the Notes or a satisfaction and discharge of the indenture. If any note is to be redeemed in part only, the notice of redemption relating to such note shall state the portion of the principal amount thereof to be redeemed. Upon surrender and cancellation of a note that is redeemed in part, the Issuer will execute and the Trustee will authenticate for the holder (at the Issuer's expense) a new note equal in principal amount to the unredeemed portion of the note surrendered and canceled. If money sufficient to pay the redemption price of and accrued and unpaid interest and additional interest (if any) on all Notes (or portions thereof) to be redeemed on the redemption date is deposited with a paying agent on or before the redemption date and certain other conditions are satisfied, on and after such date, interest will cease to accrue on the Notes of such series (or such portions thereof) called for redemption.

Ranking

The indebtedness evidenced by the Notes and the Guarantees, respectively, will be senior secured obligations of the Issuer and the Guarantors and will:

- rank equally in right of payment with the Issuer's and Guarantors' existing and future senior obligations;
- rank senior in right of payment to any of the Issuer's and Guarantors' obligations that are subordinated to the Notes and the Guarantees;
- be effectively senior in right of payment to all existing and future obligations of the Issuer and the Guarantors that are unsecured or secured by the Collateral on a junior basis to the Notes and Guarantees, in each case, to the extent of the value of the Collateral that is available to satisfy the obligations under the Notes and Guarantees;
- be effectively *pari passu* with any of the Issuer's and Guarantors' existing and future obligations that are secured by the Collateral on a second-priority basis;
- be effectively junior to any of the Issuer's and Guarantors' existing and future obligations of the Issuer and the Guarantors that are secured by the Collateral on a first- or senior-priority basis to the Notes and Guarantees, including indebtedness under the RBL facility, to the extent of the value of the Collateral; and
- be structurally subordinated to all indebtedness and other liabilities of each subsidiary of the Issuer or the Guarantors that is not a guarantor of the Notes.

As of December 31, 2023 on an as adjusted basis after giving effect to (i) the offering of Notes, (ii) the repayment of our prior reserve-based, non-recourse, syndicated loan facility (which was repaid and canceled after December 31, 2023) and (iii) the repayment of the outstanding amount of the RBL facility as described under "Use of proceeds", the Notes will constitute our only substantial financial indebtedness. Subject to customary conditions to draw, US$246.0 million would be available immediately to be redrawn under the RBL facility, which indebtedness would be first-priority secured indebtedness and therefore effectively senior to the Notes. We expect that when our interest in the Who Dat assets is added to the borrowing base, the full US$340 million committed under the RBL facility will become available, subject to customary conditions to draw.

The subsidiaries of the Parent Guarantor that will not guarantee the Notes on issuance have substantially no outstanding indebtedness, assets, liabilities, revenues or profits.

Although the indenture will limit the Incurrence of Indebtedness and the issuance of Disqualified Stock by the Parent Guarantor and the Restricted Subsidiaries, and the issuance of Preferred Stock by the Restricted Subsidiaries that are not Subsidiary Guarantors, such limitations are subject to a number of significant qualifications and exceptions. Pursuant to such qualifications and exceptions, the Parent Guarantor and its Subsidiaries may be able to Incur additional amounts of Indebtedness. Under certain circumstances the amount of such Indebtedness could be substantial and, subject to certain limitations, such Indebtedness may be Secured Indebtedness, and may be effectively senior to the Notes and Guarantees. See "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" and "Certain Covenants—Liens."

The Parent Guarantor is a holding company that has no material assets or operations other than the equity in the assets of its Subsidiaries. The Issuer is a special purpose financing vehicle that has been formed for the purpose of issuing the Notes. The Issuer has no material assets or operations. On or prior to the Issue Date, KUSA Inc. and ACN 672 679 793 Pty Ltd ("New Aus SPV") are expected to accede as Corporate Debtors under the RBL facility. Unless a Subsidiary is a Subsidiary Guarantor, claims of creditors of such Subsidiary, including trade creditors, and claims of preferred shareholders (if any) of such Subsidiary, generally will have priority with respect to the assets and earnings of such Subsidiary over the claims of creditors of the Issuer and the Parent Guarantor, including holders of the Notes. The Notes, therefore, will be structurally subordinated to holders of indebtedness and other creditors (including trade creditors) and preferred shareholders (if any) of Subsidiaries of the Issuer or the Parent Guarantor that are not Subsidiary Guarantors. As of the Issue Date, certain of the Parent Guarantor's Restricted Subsidiaries will not be Subsidiary Guarantors. The subsidiaries of the Parent Guarantor that will not guarantee the Notes on issuance have substantially no outstanding indebtedness, assets, liabilities, revenues or profits.

See "Risk Factors—Risks Related to the Notes and Security—The Notes will be structurally subordinated to all liabilities of our current and future non-Subsidiary Guarantor subsidiaries and junior to any of our future secured obligations that are secured by assets not constituting Collateral, in each case, to the extent of the value of the collateral securing such obligations."

Security

The Notes and the related Guarantees will be secured by second-priority security interests (subject to Permitted Liens) in the Collateral, which is the same Collateral that secures the RBL facility on a first priority lien basis and comprises (i) the shares or other equity interests in KEI (Brazil Santos) Pty Ltd ("KEI (Brazil Santos)"), KEI Finance 1 Pty Ltd ("KEI Finance") and Karoon Petróleo E Gás Ltda. ("KPG") as Borrowing Base Obligors, the material borrowing base assets of such Borrowing Base Obligors (including Petroleum assets which are borrowing base assets, material bank accounts, material contracts, material insurance policies, hedging policies and material intragroup loans) and an all assets general security deed or equivalent composite security over each such Australian Borrowing Base Obligor's assets and (ii) the shares or other equity interests in Karoon Energy International Pty Ltd ("KEI"), New Aus SPV, KUSA Inc. and the Issuer as Corporate Debtors and an all assets general security deed or equivalent composite security over each of the Corporate Debtors' assets, subject to the approval of the lenders under the RBL facility.

Following the Issue Date, KUSA Inc. will become a Borrowing Base Obligor and grant the holders of the Notes security over its interests in the Who Dat assets.

Prior to the date KUSA Inc. becomes a Borrowing Base Obligor, the Notes will not be secured by its borrowing base assets (except to the extent contemplated by "—Limitations on Securities Collateral" below and in particular clause (f) thereof). See "Risk Factor—Risks Related to the Notes and Security—Delivery of security interests in Collateral, which will be the case with respect to security granted over the Who Dat assets by KUSA Inc., as Guarantor of the Notes, or any Guarantees after the Issue Date increases the risk that the security interests or such Guarantees could be avoidable in bankruptcy."

Australian security

The Trustee, for and on behalf of itself and the noteholders, will accede to the Senior Lien Intercreditor Documents to receive the benefit, on a second lien basis, of the existing Australian law-governed security (as further described below) for the Notes.

Equity interests

The shares and related rights in KEI and KEI (Brazil Santos) are secured in favor of the Offshore Security Agent pursuant to, respectively, an Australian law-governed general security deed dated December 13, 2023 between the Parent Guarantor, KEI and the Offshore Security Agent (as amended on or prior to the Issue Date, the "Corporate Security GSD") and an Australian law-governed specific security deed dated December 13, 2023 between KEI and the Offshore Security Agent (the "Marketable Securities SSD"). The shares and related rights in KEI Finance are secured in favor of the Offshore Security Agent pursuant to an Australian law-governed general security deed dated December 13, 2023 between KEI Brazil Santos, KEI Finance and the Offshore Security Agent (the "Borrowing Base GSD").

The shares and related rights in New Aus SPV will be secured in favor of the Offshore Security Agent pursuant to the Corporate Security GSD.

The security interests in the above-mentioned shares and related rights will be perfected by registration on the Australian Personal Property Securities Register ("PPSR") and, to the extent certificated, by delivery to the Offshore Security Agent of the original share certificates relating to such shares and related rights together with share transfer forms executed in blank. The PPSR registrations have already been made. The aforementioned physical collateral has already been provided to the Offshore Security Agent in respect of the shares and related rights in KEI, KEI (Brazil Santos) and KEI Finance and will be provided promptly prior to, or promptly following, the Issue Date in respect of the shares and related rights in New Aus SPV.

Assets of the Borrowing Base Obligors

The assets, other than certain excluded assets as described in "—Limitations of Securities Collateral" below, of the Australian Borrowing Base Obligors are secured in favor of the Offshore Security Agent pursuant to the Borrowing Base GSD. In addition, KPG has, pursuant to a specific security deed (insurance), dated as of December 13, 2023 (the "Insurance SSD") between KPG and the Offshore Security Agent, granted security over certain insurances that are governed by the laws of a state or territory of Australia or the laws of the Commonwealth of Australia, subject to exceptions as described in "—Limitations of Securities Collateral" below.

The security interests in the assets of the Australian Borrowing Base Obligors created by the Borrowing Base GSD and the security interests in the insurances created by the Insurance SSD have been perfected by registration on the PPSR.

Corporate security

The assets, other than certain excluded assets as described in "—Limitations of Securities Collateral" below and excluding the directly-held shares and related rights in any Borrowing Base Obligor, of the Australian Corporate Debtors (other than the New Aus SPV) are secured in favor of the Offshore Security Agent pursuant to the Corporate Security GSD. The assets, other than certain excluded assets as described in "—Limitations of Securities Collateral" below, of the New Aus SPV will be secured in favor of the Offshore Security Agent pursuant to an Australian law-governed general security deed to be entered into on or prior to the Issue Date (the "Corporate Security (Accession) GSD").

The security interests in the assets of the Australian Corporate Debtors (other than the New Aus SPV) created by the Corporate Security GSD have been perfected by registration on the PPSR. The security interests in the assets of the New Aus SPV created by the Corporate Security (Accession) GSD will be registered on the PPSR prior to, or promptly following, the Issue Date.

English security

Certain English law-governed field documents relating to the borrowing base assets, hedging agreements relating to the RBL facility and insurance policies held by KPG and certain Borrowing Base Accounts (as such term is defined in the RBL facility) held by KPG in England, other than certain excluded assets as described in "—Limitations of Securities Collateral" below, are secured in favor of the Offshore Security Agent on behalf of the secured parties, including, as from the date of the Trustee's accession to the Senior Lien Intercreditor Documents, the Trustee and noteholders, pursuant to an English law-governed security agreement dated December 13, 2023 between KPG and the Offshore Security Agent (the "English Security Agreement").

The steps to perfect the security interests in the above-mentioned material agreements to which KPG is a party and the above-mentioned bank accounts include KPG providing notices to the counterparties of such agreements and notice to the relevant account bank(s) respectively, and these notices have been provided.

U.S. security

Equity interests

The shares of capital stock and related rights in KUSA Inc. and the Issuer will be secured in favor of the Offshore Security Agent each pursuant to New York law-governed equity pledge agreements to be entered into on or before the Issue Date between the New Aus SPV and the Offshore Security Agent (each a "U.S. Equity Pledge Agreement").

The security interests in the above-mentioned shares of capital stock and related rights will be perfected by the filing of a financing statement in the form prescribed by the Uniform Commercial Code, as in effect in the District of Columbia, in the office of the Recorder of Deeds of the District of Columbia and, to the extent such shares of capital stock and related rights are certificated securities, by delivery of the certificates representing such shares of capital stock and related rights in registered form, issued or endorsed in the name of the Offshore Security Agent or in blank or accompanied by undated stock powers duly endorsed in blank.

Corporate security

The assets, other than certain excluded assets as described in "—Limitations of Securities Collateral" below, of KUSA Inc. and the Issuer will be secured in favor of the Offshore Security Agent pursuant to New York law-governed security agreements to be entered into on or prior to the Issue Date (each a "U.S. Security Agreement").

The security interests in the assets of KUSA Inc. and the Issuer will be perfected by registration of a financing statement in the form prescribed by the Uniform Commercial Code, as in effect in the State of Delaware, in the office of the Delaware Secretary of State and, to the extent the collateral thereunder comprises shares of capital stock and related rights in another Issuer or Guarantor, by delivery of the certificates representing such shares of capital stock and related rights in registered form, issued or endorsed in the name of the Offshore Security Agent or in blank or accompanied by undated stock powers duly endorsed in blank.

Brazilian security

Equity interests

The second priority Lien security interests over all Equity Interests in KPG (the "Brazilian Share Collateral") will be effected pursuant to a pledge in the form of an amendment to the fiduciary transfer of quotas agreement (*contrato de alienação fiduciária em garantia*) (the "Brazilian Share Pledge Agreement") currently in place under the RBL facility to include the Notes as secured obligations and the Trustee and noteholders as secured parties thereunder. The Brazilian Share Pledge Agreement will be governed by the laws of Brazil. The amendment to the Brazilian Share Pledge Agreement will be entered into on or before the Issue Date and will be subject to customary registration and perfection requirements in accordance with and as required by the Security Documents.

Under the terms of the indenture and the Security Documents, the Issuer and the Guarantors will covenant and agree that:

(a) the amendment to the Brazilian Share Pledge Agreement and any related ancillary document will be executed on or before the Issue Date (subject to the term disclosed in clause (c));

(b) all internal procedures relating to the Brazilian Share Pledge Agreement and any related ancillary document shall be duly completed by the Issuer and the relevant Guarantors as of the Issue Date;

(c) KPG's articles of association shall be amended to reflect the Lien of the Trustee and the holders of the Notes, which filing must occur prior to or on the Issue Date, and be duly registered with the competent Board of Trade (*Junta Comercial*) within 20 days of the Issue Date, except if KPG is complying in good faith with a request from the appropriate Board of Trade (*Junta Comercial*) and has provided evidence to the Onshore Security Agent, the Trustee and noteholders of such request and is endeavoring to comply with such request, in which case the term to complete such registrations may be extended accordingly for an additional 20 days;

(d) the Brazilian Share Pledge Agreement shall be filed with the competent Registry of Titles and Deeds in Brazil (*Cartórios de Registro de Títulos e Documentos*) (the "RTD") prior to or on the Issue Date, and the relevant registration must be obtained within eight Business Days from the execution of the Brazilian Share Pledge Agreement; the term to complete such registrations shall be extended for an additional eight days if KPG is complying in good faith with a request from the appropriate RTD and has provided evidence to the Onshore Security Agent, the Trustee and the noteholders of such request and is endeavoring to comply with such request; and

(e) the security interests of the holders of the Notes in the Brazilian Share Collateral shall, therefore, be perfected within eight Business Days of execution (subject to any extension as specified in the foregoing clause (d)).

Prior to the date of registration with the competent RTD and competent Board of Trade (*Junta Comercial*), as described above, the holders of the Notes will not have a perfected security interest in the Brazilian Share Collateral.

Concessions

Concession Agreements

As collateral for the benefit of the holders of the Notes, on or prior to the Issue Date, KPG shall enter into an amendment to the pledge of concessions emerging rights agreement (the "Concessions Rights Pledge Agreement") relating to their rights under each concession agreement in Brazil which comprises part of the borrowing base under the RBL facility (the "Brazilian Concessions Collateral") currently in place under the RBL facility to include the Notes as secured obligations and the Trustee and noteholders as secured parties thereunder. The Concessions Rights Pledge Agreement will be governed by the laws of Brazil and the amendment will be subject to certain registration and perfection requirements, as provided under the Concession Rights Pledge Agreement.

The security interest in the Brazilian Concessions Collateral will be perfected with the registration of the Concession Rights Pledge Agreement with the competent RTD and the delivery of a notice to ANP pursuant to the terms under article 23 of ANP's Resolution No. 785/2019.

Under the terms of the indenture and the Security Documents, the Issuer and the Guarantors will covenant and agree that:

(a) the Concession Rights Pledge Agreement and any related ancillary document will be executed on or before the Issue Date;

(b) all internal procedures relating to the Concession Rights Pledge Agreement and any related ancillary document shall be duly completed by the Issuer and the relevant Guarantors as of the Issue Date;

(c) the filing of the Concession Rights Pledge Agreement shall be made with the competent RTD prior to or on the Issue Date, and the relevant registration must be obtained within eight days from the execution of the Concessions Rights Pledge Agreement; the term to complete such registration shall be extend for an additional eight days if KPG is complying in good faith with a request from the competent RTD and has provided evidence to the Onshore Security Agent, the Trustee and noteholders of such request and is endeavoring to comply with such request;

(d) the security interests of the holders of the Notes in the Brazilian Concessions Collateral shall therefore be perfected within eight Business Days of the execution of the Concessions Rights Pledge Agreement (subject to any extension as specified in the foregoing clause (c)); and

(e) the notification to ANP pursuant to the terms under article 23 of ANP's Resolution No. 785/2019 shall be made by KPG within five Business Days of the execution of the Concessions Rights Pledge Agreement but in any case prior to or on the Issue Date.

The second priority Lien over the Brazilian Concessions Collateral will be valid, effective and perfected against third parties (other than ANP) upon registration of the Concession Rights Pledge Agreement before the competent RTD, subject to delivery of the notification to ANP, which is a condition for the effectiveness and perfection of the amended Concession Rights Pledge Agreement before ANP, in accordance with the applicable laws and the rules provided in ANP regulations. Prior to the date of registration and delivery of the notice to ANP, the holders of the Notes will not have a perfected security interest in the Brazilian Concessions Collateral.

Crude Oil

As collateral for the benefit of the holders of the Notes, on or prior to the Issue Date, KPG shall enter into an amendment to the pledge of oil agreement with respect to all crude oil produced and extracted pursuant to the concession agreements in Brazil which comprise part of the borrowing base under the RBL facility (the "Crude Oil Pledge Agreement") currently in place under the RBL facility to include the Notes as secured obligations and the Trustee and the noteholders as secured parties thereunder. The Crude Oil Pledge Agreement will be governed by the laws of Brazil. The amendment will grant the holders of the Notes a second priority Lien over such crude oil (the "Brazilian Crude Oil Collateral"), subject to certain registration and perfection requirements, as provided under the Crude Oil Pledge Agreement.

Under the terms of the indenture and the Security Documents, the Issuer and the Guarantors will covenant and agree that:

(a) the Crude Oil Pledge Agreement and any related ancillary document will be executed on or before the Issue Date;

(b) all internal procedures relating to the Crude Oil Pledge Agreement and any related ancillary document shall be duly completed by the Issuer and the relevant Guarantors as of the Issue Date;

(c) the filing of the Crude Oil Pledge Agreement shall be made with the competent Real Estate Registry in Brazil prior to or on the Issue Date, and the relevant registration must be obtained within 20 days from the relevant filing with Real Estate Registry, except if KPG is complying in good faith with a request from the competent Real Estate Registry and has provided evidence to the Onshore Security Agent, the Trustee and noteholders of such request and is endeavoring to comply with such request, in which case the term to complete such registrations may be extended accordingly for an additional 20 days or subsequent periods of 20 days as long as KPG demonstrates further requests from the competent Real Estate Registry and provides evidence to the Onshore Security Agent, the Trustee and noteholders of such requests and that it is endeavoring to comply with such requests; and

(d) the security interests of the holders of the Notes in the Brazilian Crude Oil Collateral shall therefore be perfected within 20 days of the relevant filing with the Real Estate Registry (subject to any extension as specified in the foregoing clause (c)).

Prior to the date of registration the holders of the Notes will not have a perfected security interest in the Brazilian Crude Oil Collateral.

Credit Receivables and Step-in Rights

The security interests over all material credit receivables and step-in rights over certain material agreements of KPG relating to the borrowing base assets ("Brazilian Assignment of Receivables and Conditional Assignment of Contracts") will be effected pursuant to an amendment to the conditional assignment of contracts and fiduciary assignment of credit rights agreement (the "Brazilian Assignment of Receivables and Conditional Assignment of Contracts Agreement") currently in place under the RBL facility to include the Notes as secured obligations and the Trustee and noteholders as secured parties thereunder. The Brazilian Assignment of Receivables and Conditional Assignment of Contracts will be governed by the laws of Brazil. The amendment will be entered into on or prior to the Issue Date. The Brazilian Assignment of Receivables and Conditional Assignment of Contracts will provide the holders of the Notes with a second priority Lien over the credit receivables of KPG arising out of agreements or instrument that are material assets, the Borrowing Base Accounts held in Brazil, certain material contracts governed by Brazilian law relating to the borrowing base assets and insurance policies governed by Brazilian law that are material assets, other than, in each case, the excluded assets specified therein. The Brazilian Assignment of Receivables and Conditional Assignment of Contracts will be subject to customary registration and perfection requirements in accordance with and as required by the Security Documents.

Under the terms of the indenture and the Security Documents, the Issuer and the Guarantors will covenant and agree that:

(a) the Brazilian Assignment of Receivables and Conditional Assignment of Contracts Agreement will be executed on or before the Issue Date;

(b) all internal procedures relating to the Brazilian Assignment of Receivables and Conditional Assignment of Contracts and any related ancillary document shall be duly completed by the Issuer and the relevant Guarantors as of the Issue Date;

(c) KPG shall (i) deliver notice to the relevant counterparties within five Business Days of execution of the Brazilian Assignment of Receivables and Conditional Assignment Contracts Agreement but in any case prior to or on the Issue Date and (ii) use all reasonable endeavors to obtain acknowledgements and consents from the relevant counterparties promptly following the Issue Date;

(d) the filing of the Brazilian Assignment of Receivables and Conditional Assignment of Contracts Agreement shall be made with the competent RTD prior to or on the Issue Date, and the relevant registration must be obtained within eight Business Days from the execution of the Brazilian Assignment of Receivables and Conditional Assignment of Contracts Agreement; the term to complete such registrations shall be extended for an additional eight days if KPG is complying in good faith with a request from the appropriate RTD and has provided evidence to the Onshore Security Agent, the Trustee and noteholders of such request and is endeavoring to comply with such request; and

(e) the security interests of the holders of the Notes in the credit rights and contractual rights shall be perfected within eight Business Days of the execution of the Brazilian Assignment of Receivables and Conditional Assignment of Contracts Agreement for the assigned credit rights that do not require acknowledgements and consents and as soon as acknowledgements and consents are obtained for the assigned credit rights that required consent and for the conditional assignment of contractual rights (subject to any extension as specified in the foregoing clause (d)).

Prior to the date registrations are obtained and/or consents are received (as applicable) in respect of (i) the conditional assignment of contractual rights and (ii) the assignment of credit rights for the assigned rights that require such consents, the holders of the Notes will not have a perfected security interest in the Brazilian Assignment of Receivables and Conditional Assignment of Contracts. The security interest of the holders of the Notes under the fiduciary assignment of credit rights will be perfected upon delivery of a notice to the relevant counterparty, unless the assigned rights specifically require obtaining a consent, in which case the security interest will only be perfected once the relevant consent is received.

Equipment

The security interests over all material equipment relating to the borrowing base assets owned by KPG other than certain customary excluded assets (the "Brazilian Equipment Collateral") will be effected pursuant to an amendment to the fiduciary transfer of equipment agreement (the "Brazilian Equipment Pledge Agreement") currently in place under the RBL facility to include the Notes as secured obligations and the noteholders and the Trustee as secured parties thereunder. The Brazilian Equipment Pledge Agreement will be governed by the laws of Brazil. The amendment will be entered into on or prior to the Issue Date. Perfection of the second priority Lien security interest over the Brazilian Equipment Collateral in favor of the holders of the Notes will be subject to customary registration and perfection requirements in accordance with and as required by the Security Documents.

Under the terms of the indenture and the Security Documents, the Issuer and the Guarantors will covenant and agree that:

(a) the Brazilian Equipment Pledge Agreement and any related ancillary document will be executed on or before the Issue Date;

(b) all internal procedures relating to the Brazilian Equipment Pledge Agreement and any related ancillary document shall be duly completed by the Issuer and the relevant Guarantors as of the Issue Date;

(c) the filing of the Brazilian Equipment Pledge Agreement shall be made with the competent RTD prior to the Issue Date and is a condition for settlement, and the relevant registration must be obtained within eight Business Days from the execution of the Brazilian Equipment Pledge Agreement; the term to complete such registrations shall be extended for an additional eight days if KPG is complying in good faith with a request from the appropriate RTD and has provided evidence to the Onshore Security Agent, the Trustee and noteholders of such request and is endeavoring to comply with such request; and

(d) the security interests of the holders of the Notes in the Brazilian Equipment Collateral shall be perfected, therefore, within eight Business Days of the execution of the Brazilian Equipment Pledge Agreement (subject to any extension as specified in the foregoing clause (c)).

Prior to the date of registration the holders of the Notes will not have a perfected security interest in the Brazilian Equipment Collateral.

The date on which the foregoing steps (other than the requirements under clause (c)(ii) under "Credit Receivables and Step-in Rights") are completed and perfection requirements in Brazil are satisfied as described in this section, "Brazilian Security," is referred to in this "Description of the Notes" as the "Brazilian Perfection Date."

Additionally, the Brazilian Guarantors expressly waive, to the fullest extent permitted by applicable law, any and all rights and/or benefits they may have under Article 333 and Articles 366, 368, 369, 821, 822, 827, 829, 830, 834, 835, 837, 838 and 839 of Brazilian Law No. 10,406 dated as of January 10, 2022 and Articles 130 and 794 of the Brazilian Law No. 13,105 dated as of March 16, 2015 (or any successor law thereto).

Limitations on Securities Collateral

The Collateral is subject to customary exclusions and limitations, including the following:

(a) any asset (including any contract, lease, authorization, or other third party arrangement) if the creation or perfection of the security would breach or constitute a default (however described) under or violation of, or require any consent or authorization under, any contract, lease, authorization or other third party arrangement or applicable law or regulation (or assets which, if subject to the security, would give a third party a right to terminate or otherwise amend any rights, benefits and/or obligations with respect to the Parent Guarantor or any of its Subsidiaries and/or such assets or require any of the Parent Guarantor or any of its Subsidiaries to take any action adverse to any of the Parent Guarantor or any of its Subsidiaries), provided that the Issuer and Guarantors will use commercially reasonable efforts to obtain consent to security over any such assets if such asset is material to the Parent Guarantor and its Subsidiaries and creating security over such assets is required by the applicable financing documentation (such excluded assets, "Restricted Assets");

(b) any (i) payroll and other employee wage and benefit accounts with respect to which the granting or perfection of a security interest would reasonably be expected to violate applicable law or regulation, (ii) tax accounts, including, without limitation, sales tax accounts, income tax accounts, and federal, state or local employment tax accounts with respect to which the granting or perfection of a security interest would reasonably be expected to violate applicable law or regulation, (iii) contractual escrow accounts held for the benefit of third parties in connection with any acquisition, investment or disposal permitted under the financing documents, or (iv) fiduciary or trust accounts held for the benefit of third parties (including any governmental authority, officers or employees), in each case that are not required to be Borrowing Base Accounts under the RBL facility and are otherwise permitted to be held by the Issuer and Guarantors;

(c) with respect to any U.S. Issuer or Guarantor or assets in the United States (including shares in any U.S. entity), the security will not include (i) any vehicles and other assets subject to certificates of title statutes, except to the extent the perfection of security interests in such vehicle is accomplished solely by the filing of an all assets UCC financing statement or similar filing in a jurisdiction other than the US, (ii) any "intent to use" trademark applications for which a statement of use or an amendment to alleged use has not been filed, but only to the extent (if any) that and solely during the period, if any, in which the grant of a security interest therein would impair the validity or enforceability of such "intent to use" trademark application or any registration that issues therefrom under applicable law, (iii) any fee-owned real property which is not a material asset, (iv) any leasehold interests in real property (it being understood there shall be no requirement to obtain any landlord waivers, estoppels, collateral access letters or similar third-party agreements or consents), and (v) margin stock;

(d) only wholly-owned Subsidiaries will be required to grant security;

(e) the giving or perfection of security will not be required if it would restrict, in any material respect, the ability of the Parent Guarantor or any of its Subsidiaries to conduct its operations and business in the ordinary course as otherwise permitted by the financing documents;

(f) security over the assets of Issuer and Guarantors other than Borrowing Base Obligors will be limited to the equity interests in the Issuer and Guarantors (other than the Parent Guarantor) and wholly-owned material Subsidiaries, material intra-group receivables and material operating bank accounts, and where customary, a floating general security (or equivalent) over other assets of such Issuer or Guarantor;

(g) no security will be taken over goods (including inventory), moveable plant, equipment, vehicles or receivables if it would require labelling, segregation, periodic listing, notification, mapping or specification; and

(h) the Issuer and Guarantors will not be required to investigate title, provide insurance (including title insurance), surveys or other reports in relation to any collateral.

without limiting the foregoing, each Borrowing Base Obligor will:

(1) promptly notify the relevant Common Security Agent if a Borrowing Base Obligor (i) is a party to, or enters into, any agreement or instrument relating to the borrowing base assets under which the Borrowing Base Obligor's revenues or expenditures could reasonably be expected to exceed US$5,000,000 in aggregate in any calendar year; or (ii) owns or acquires any item of plant, machinery, equipment or other asset relating to the borrowing base assets with an acquisition cost exceeding US$5,000,000, (other than assets the subject of Permitted Security) (each asset in the foregoing subclause (i) and (ii), a "Material Asset");

(2) if a Material Asset is excluded from the Collateral on the basis it is a Restricted Asset, unless the relevant secured party representative otherwise agrees, use reasonable endeavors to obtain, as soon as reasonably practicable, all relevant consents, approvals or authorizations such that the Material Asset will cease to be a Restricted Asset; and

(3) if a Material Asset is not, or ceases to be, a Restricted Asset, promptly take any action required under the applicable security document or otherwise reasonably required by the applicable Common Security Agent, to create and/or perfect security over such Material Asset in accordance with the financing documents (including the security principles set out under this "Limitations on Securities Collateral").

There will be no "fixed" security (or equivalent) over cash, cash equivalents, receivables, investments or bank accounts nor will there be any blocked bank accounts (other than any "cash cover" account) prior to the security becoming enforceable. Notification of security will be given to the account bank and/or the Parent Guarantor and its Subsidiaries will use reasonable commercial efforts to obtain a springing account control agreement, in each case where required to perfect security over a material bank account provided that this is not inconsistent with the Parent Guarantor and its Subsidiaries retaining control over and the ability to use freely the balance of the account until the security becomes enforceable. For the avoidance of doubt, no account control agreement or account bank acknowledgement will be required in a jurisdiction where it is not customary to obtain such an agreement or acknowledgement. Any security over bank accounts will be subject to any prior security, set-off or equivalent rights in favor of the account bank at law or under its standard terms and conditions. Until the security becomes enforceable, the Parent Guarantor and its Subsidiaries will be entitled to transfer and deal with cash, cash equivalents, receivables, investments and bank accounts provided that in doing so it does not otherwise breach the terms of the security. Prior to the security becoming enforceable, none of the Parent Guarantor or its Subsidiaries will be required to perfect a security interest over intra-group indebtedness, other than by the filing of a UCC financing statement or an Australian PPSA filing (or equivalent filings in other jurisdictions).

The security documents will each be governed by the laws of the country in which the Issuer or Guarantor is located, provided that the relevant security document in respect of shares in an Issuer or Guarantor will be governed by the laws of the country of the Issuer or Guarantor whose shares are being secured and not by the law of the country of the Issuer or Guarantor granting the security, provided, further, that shares of entities that are not the Issuer or a Guarantor may be subject to any general security given by the Issuer or Guarantor under the laws of the Issuer's or Guarantors' jurisdiction and shares of any Issuer or Guarantor may also be subject to any general security given by the Issuer or Guarantor under the laws of the Issuer's or Guarantors' jurisdiction. Subject to the foregoing, no local law governed security is required to be granted over the shares of any of the Parent Guarantor and its Subsidiaries that is not the Issuer or a Guarantor.

In addition, certain other security principles apply that may prevent or limit each of the Parent Guarantor or any of its Subsidiaries from providing security, including:

(i) in determining the security to be provided by the Parent Guarantor and its Subsidiaries (including, if applicable, any limitation on the secured amount), the parties will take into account the cost of providing such security so as to ensure it is proportionate to the benefit accruing to the beneficiaries (including, without limitation, tax consequences, notarization and perfection expenses);

(ii) legal limitations, requirements and restrictions (including financial assistance, corporate benefit, capital maintenance rules, fraudulent preference, "earnings stripping", "controlled foreign corporation" and "thin capitalization" rules, tax restrictions, retention of title claims and similar principles) may prevent or limit each of the Parent Guarantor or any of its Subsidiaries from providing security or may require that the security be limited in amount or otherwise; provided that, to the extent lawful and customary, commercially reasonable efforts will be used to overcome such restriction if doing so would not be materially adverse to any of the Parent Guarantor and its Subsidiaries;

(iii) security will not be required if giving such security would expose any officers of the relevant company to risk of personal or criminal liability (taking into account any limitations on such credit support); provided that reasonable commercial efforts will be used to overcome any such obstacle; and

(iv) it is acknowledged that in certain jurisdictions (including Brazil) it may be either legally impractical or impossible or would unduly disrupt the business of the each of the Parent Guarantor or any of its Subsidiaries as permitted under the debt documents in any material respect to grant security over certain categories of assets in which event security will not be taken over such assets.

The security documents will not operate so as to prohibit or restrict any transaction which is permitted by the debt documents, and the applicable Common Security Agent will do all things reasonably requested to release security in respect of assets or shares the subject of a permitted disposal.

Security will only become enforceable if the relevant secured creditors have taken certain acceleration action under the applicable secured debt documents.

Any power of attorney granted to the secured parties under the security documents may only be exercised upon the security becoming enforceable or following a failure to comply with any further assurance or perfection obligation which has not been remedied within a specified period following notice from the applicable Security Agent.

After-Acquired Property

Subject to the matters summarized in "—Limitations on securities collateral" above, the Issuer and the Guarantors will grant and perfect security over after-acquired property.

Security Documents

The security documents establishing the Shared Collateral (as defined below) granted for the benefit of the secured parties, including, as from the date of the Trustee's accession to the Senior Lien Intercreditor Documents, the Trustee and noteholders, will comprise:

- the following Australian law-governed security documents: the Borrowing Base GSD, the Corporate Security GSD, the Marketable Securities SSD, the Insurance SSD and the Corporate Security (Accession) GSD;

- the following English law-governed security document: the English Security Agreement;
- the following New York law-governed security documents: the U.S. Equity Pledge Agreements and the U.S. Security Agreements; and
- the following Brazilian law-governed security documents: the Brazilian Share Pledge Agreement, the Concessions Rights Pledge Agreement, the Crude Oil Pledge Agreement, the Brazilian Assignment of Receivables and Conditional Assignment of Contracts and the Brazilian Equipment Pledge Agreement and the above-mentioned amendments thereto.

On the Issue Date, the Trustee will join the Senior Lien Intercreditor Documents as a second lien representative for itself and as agent of the noteholders, and the Trustee and noteholders will become second lien creditors for the purposes of the Senior Lien Intercreditor Documents. Pursuant to the Senior Lien Intercreditor Documents, the Common Security Agents hold the security interests established pursuant to the security documents in favor of all secured parties, including the Trustee and noteholders on a second-priority basis. See "—Senior Lien Intercreditor Documents" below.

Senior Lien Intercreditor Documents

On the Issue Date, the Trustee will join the Senior Lien Intercreditor Documents as a second lien representative for itself and as agent of the holders of the Notes and, by purchasing a note, each holder of a note shall be deemed to have agreed to, and be bound by the terms and conditions of, the Senior Lien Intercreditor Documents as a second lien creditor.

Reference is made to the Senior Lien Intercreditor Documents for a full disclosure of all defined terms used therein, as well as any other capitalized terms used herein for which no definition is provided in this "—Senior Lien Intercreditor Documents" section.

Collateral agency

The Security Agency and Subordination Deed establishes a collateral agency and trust arrangement pursuant to which the Common Security Agents will hold security granted by the Debtors over Collateral as agent and trustee for the benefit of the following persons (such persons in (a) through (c) below, collectively, together with the Common Security Agents and the Intercreditor Agent, the "Secured Parties"): (a) the lenders, agent, hedge counterparties and other finance parties from time to time under the RBL facility (collectively, the "Initial Facility Creditors" and, together with the holders of other indebtedness that is from time to time designated as a "Borrowing Base Facility" under the Security Agency and Subordination Deed, the representative thereof (any such representative, being as of the Issue Date the Initial Facility Agent, the "Borrowing Base Representative") and any hedge counterparties under any other hedging arrangements designated as "Borrowing Base Hedging Agreements" under the Security Agency and Subordination Deed, collectively, the "Borrowing Base Creditors"), (b) holders of indebtedness that is from time to time designated as a "Senior Secured Facility" under the Security Agency and Subordination Deed (collectively, together with their respective representative(s) (each such representative, a "Senior Secured Representative") and together with the Borrowing Base Representative, a "First Lien Representative") and any hedge counterparties under hedging arrangements designated as "Senior Secured Hedging Agreements" under the Security Agency and Subordination Deed, the "Senior Secured Creditors" and, together with the Borrowing Base Creditors, the "First Lien Creditors"), (c) holders of indebtedness (including holders of the Notes) that is from time to time designated as a "Second Lien Facility" under the Security Agency and Subordination Deed (collectively, together with their respective representative(s) (each such representative, a "Second Lien Representative") and any hedge counterparties under hedging arrangements designated as "Second Lien Hedging Agreements" under the Security Agency and Subordination Deed, collectively, the "Second Lien Creditors"), and (d) the holders of indebtedness (including, without limitation, any overdraft or other current account facility, any foreign exchange facility, any guaranty, bonding, documentary or standby letter of credit facility, any credit card or automated payment facility, any short term loan facility, any derivatives facility, any cash pooling or other cash management arrangement) which, in each case, is designated as an "Operating Facility" under the Security Agency and Subordination Deed (collectively, "Operating Facility Lenders" and, together with the Borrowing Base Creditors, the Senior Secured Creditors and the Second Lien Creditors, the "Secured Creditors"). The Security Agency and Subordination Deed includes mechanics providing for the release of transaction security to permit certain non-distressed disposals of Collateral and the giving of enforcement instructions to the Common Security Agents and the application of proceeds of recovery of the Collateral, provisions to facilitate sharing of the benefit of Collateral held by the Common Security Agents with transferees and providers of permitted replacement or additional secured indebtedness, and customary agent protective provisions for the benefit of the Common Security Agents and Intercreditor Agent. The Security Agency and Subordination Deed contains provisions dealing with certain intra-Group indebtedness owed by the Debtors, including restrictions on when payments may be made and enforcement action may be taken, with respect to such intra-Group indebtedness, restrictions on the taking of security with respect to such intra-Group indebtedness (such provisions, collectively, the "Intra-Group Liability Subordination") and turnover provisions. Certain lenders that provide unsecured indebtedness or financial accommodation to the Group that is from time to time designated as a "Senior Unsecured Facility" under the Security Agency and Subordination Deed (collectively, "Senior Unsecured Creditors") may, but are not obliged to, become party to the Security Agency and Subordination Deed only to receive the benefit of the Intra-Group Liability Subordination. Operating Facility Lenders that join the Security Agency and Subordination Deed may benefit from the liens on the Collateral held by the Common Security Agents on a first lien basis (*pari passu* with the Senior Secured Creditors in respect of the Borrowing Base Priority Collateral and *pari passu* with the First Lien Creditors in respect of the Corporate Collateral) or on a second lien basis pari passu with the Second Lien Creditors, and are not required to join the Senior Lien Intercreditor Agreement. In the event of any inconsistency between the terms of the Security Agency and Subordination Deed and the terms of the other Debt Documents, the Security Agency and Subordination Deed prevails, provided that the Senior Lien Intercreditor Agreement (or any other "Intercreditor Agreement" from time to time as defined in the Security Agency and Subordination Deed, which will include the Second Lien Pari Passu Intercreditor Agreement upon entry into thereof – see "—Second Lien Pari Passu Intercreditor Agreement") prevails as between the relevant parties or creditor representatives on their behalf that are party to the Senior Lien Intercreditor Agreement or such other intercreditor agreement (other than with respect to the provisions of the Security Agency and Subordination Deed relating to the rights and duties of the Common Security Agents and Intercreditor Agent).

Lien subordination and application of proceeds

The Senior Lien Intercreditor Agreement provides that the liens on the Collateral held by or on behalf of any Common Security Agent, any Secured Debt Representative or any other Secured Party shall rank and secure the Secured Obligations in the following order of priority (and such Secured Obligations shall be junior and subordinate in right of any such higher ranking Secured Obligations):

Borrowing Base Priority Collateral: In the case of Collateral comprising (a) assets and property of the Borrowing Base Obligors, (b) capital stock of the Borrowing Base Obligors directly owned by a Debtor, (c) books and records related to any and all of the foregoing and (d) all products and proceeds of any and all of the foregoing (collectively, "Borrowing Base Priority Collateral"):

(1) First, the indebtedness and other liabilities owed by the Debtors to the Intercreditor Agent or the Borrowing Base Creditors under the applicable financing documents evidencing or governing the terms of such indebtedness or liabilities (the "Borrowing Base Obligations" and such financing documents the "Borrowing Base Debt Documents");

(2) second, to the extent expressed to be secured thereby, the indebtedness and other liabilities owed by the Debtors to the Senior Secured Creditors under the applicable financing documents evidencing or governing the terms of such indebtedness or liabilities (the "Senior Secured Obligations" and, together with the Borrowing Base Obligations, the "First

Lien Obligations", and such financing documents the "Senior Secured Debt Documents" and, together with the Borrowing Base Debt Documents, the "First Lien Debt Documents"), *pari passu* and without preference between them (subject to the terms of the applicable Senior Secured Debt Documents, including any *pari passu* senior secured intercreditor agreement if there is more than one series of Senior Secured Obligations); and

(3) third, to the extent expressed to be secured thereby, the liabilities and other liabilities owed by the Debtors to the Second Lien Creditors under the applicable financing documents evidencing or governing the terms of such indebtedness or liabilities (which includes the liabilities owed by the Debtors with respect to the Notes) (the "Second Lien Obligations" and, together with the Borrowing Base Obligations and the Senior Secured Obligations, the "Secured Obligations", and such financing documents, the "Second Lien Debt Documents" and, together with the Borrowing Base Debt Documents and the Senior Secured Debt Documents, the "Secured Debt Documents"), *pari passu* and without preference between them (subject to the terms of the applicable Second Lien Debt Documents, including the Second Lien Pari Passu Intercreditor Agreement or any other applicable *pari passu* Second Lien Pari Passu Intercreditor Agreement if there is more than one series of Second Lien Obligations).

Corporate Collateral: In the case of Collateral other than Borrowing Base Priority Collateral (collectively, the "Corporate Collateral"):

(1) first, to the extent expressed to be secured thereby, the First Lien Obligations *pari passu* and without preference between them (subject to the terms of the applicable First Lien Debt Documents, including any applicable *pari passu* senior secured intercreditor agreement if there is more than one series of Senior Secured Obligations); and

(2) second, to the extent expressed to be secured thereby, the Second Lien Obligations (including indebtedness with respect to the Notes) *pari passu* and without preference between them (subject to the terms of the applicable Second Lien Debt Documents, including the Second Lien Pari Passu Intercreditor Agreement or any applicable *pari passu* Second Lien Pari Passu Intercreditor Agreement if there is more than one series of Second Lien Obligations).

The order of application of amounts received or recovered by the Common Security Agents or other applicable Secured Parties in connection with enforcement of security over the Collateral reflects the ranking and priority of liens described above; provided that sums owing to the Common Security Agents, any receiver, any delegate, or the Intercreditor Agent are to be paid ahead of indebtedness owing to other Secured Parties.

Collateral consisting of cash and cash equivalents pledged to secure Secured Obligations under a debt facility consisting of reimbursement obligations in respect of letters of credit or otherwise held by the applicable representative with respect to any letter of credit, prepayment obligation or defaulting lender, as applicable, shall be applied as specified in the applicable Secured Debt Document and will not constitute Shared Collateral.

Modifications to First Lien Obligations

Under the Senior Lien Intercreditor Agreement, each Second Lien Representative (on behalf of itself and the Second Lien Creditors it represents) (which includes the Trustee on behalf of itself and the holders of the Notes) acknowledges that (a) the Senior Priority Obligations may be revolving in nature and that the amount thereof that may be outstanding may be increased or reduced and subsequently reborrowed, (b) the terms of the Senior Priority Obligations may be amended, restated, amended and restated, supplemented or otherwise modified, and the Senior Priority Obligations, or a portion thereof, may be refinanced from time to time and (c) the aggregate amount of the Senior

Priority Obligations may be increased, in each case, without notice to or consent by the Second Lien Representatives or the Second Lien Creditors, so long as such increase is not prohibited by the Second Lien Debt Documents. The Senior Lien Intercreditor Agreement also contains similar acknowledgments by the First Lien Representatives in favor of the Second Lien Representatives with respect to modifications to Second Lien Debt Documents, provided that any such modification of Second Lien Debt Documents shall not affect the priority of liens provided for by the Senior Lien Intercreditor Agreement.

Prohibition on contesting liens and restriction on further liens for the benefit of Second Lien Obligations

Under the Senior Lien Intercreditor Agreement (a) each Secured Party agrees that it shall not (and waives any right to), directly or indirectly, object to, contest or support any other person in objecting to or contesting, in any proceeding (including any insolvency or liquidation proceeding and any insolvency event), (i) the validity, extent, perfection, priority or enforceability of any lien securing any Secured Obligations held (or purported to be held) by or on behalf of a Common Security Agent for the benefit of any Secured Parties, or by any Secured Debt Representative or by any of the other Secured Parties or any other agent or trustee thereof in any Collateral or the allowability of any claims asserted with respect to any Secured Obligations in any proceeding (including any insolvency or liquidation proceeding and any insolvency event), (ii) the validity or enforceability of any Common Collateral Documents or any Secured Obligations thereunder, or (iii) the relative rights and duties of the holders of any Secured Obligations established or granted and/or established in the Senior Lien Intercreditor Agreement or any other Secured Debt Document with respect to such liens, and (b) until the discharge of the Senior Priority Obligations, no Debtor may grant any additional liens on the Collateral to secure any Second Lien Obligations unless (x) doing so is expressly permitted under the First Lien Debt Documents or (y) it has also granted or concurrently also grants, a lien on such Collateral to (i) the applicable Common Security Agent for the benefit of the Borrowing Base Secured Parties or to the Borrowing Base Representative to secure the Borrowing Base Obligations and (ii) the Senior Secured Parties or the Senior Secured Representatives to secure the Senior Secured Obligations. The Senior Lien Intercreditor Agreement also provides for the Debtors to grant certain corresponding liens for the benefit of the Second Lien Creditors (including holders of the Notes) where additional liens are created on the Collateral of the Debtors for the benefit of First Lien Creditors.

Enforcement action and Second Priority Enforcement Date

Subject to the terms of the Senior Lien Intercreditor Documents and any applicable *pari passu* intercreditor agreement, the Common Security Agents will (i) take enforcement action in relation to the Collateral in accordance with the instructions of the Intercreditor Agent acting on the instructions of (a) with respect to the Borrowing Base Priority Collateral or enforcement action against a Borrowing Base Obligor, (x) prior to the discharge of Borrowing Base Obligations, the Borrowing Base Representative and (y) following the discharge of Borrowing Base Obligations and prior to the discharge of the First Lien Obligations, the First Lien Representative (or, if there is more than one series of First Lien Obligations, the First Lien Representative entitled to give instructions under the applicable pari passu intercreditor agreement) (the "Designated First Lien Representative") and (z) following the discharge of First Lien Obligations and prior to the discharge of Second Lien Obligations, the Second Lien Representative (or, if there is more than one series of Second Lien Obligations, the Second Lien Representative entitled to give instructions under the Second Lien Pari Passu Intercreditor Agreement or other applicable pari passu intercreditor agreement) (the "Designated Second Lien Representative"), and (b) with respect to Corporate Collateral or enforcement action against a Corporate Debtor, (x) prior to the discharge of the First Lien Obligations, the Designated First Lien Representative, and (y) on or after the discharge of the First Lien Obligations and prior to the discharge of the Second Lien Obligations, the Designated Second Lien Representative (such representative that is entitled to give such instructions to the Intercreditor Agent, the "Relevant Designated Representative"), and (ii) take any other action in accordance with the directions of each Relevant Designated Representative.

As of the Issue Date, the Borrowing Base Representative is the Relevant Designated Representative.

The Senior Lien Intercreditor Agreement provides that, whether or not any insolvency event has occurred or any insolvency or liquidation proceeding has been commenced by or against any Debtor, and subject as described below, no Secured Debt Representative or Secured Party other than a Senior Priority Representative or Senior Priority Secured Party, as applicable (each such Secured Debt Representative a "Junior Secured Representative" and each such Secured Party a "Junior Secured Party", as applicable), will (i) undertake, join with any person taking, or be entitled to direct (or instruct the Intercreditor Agent to direct) any Common Security Agent to commence or maintain, any enforcement of any lien on any Collateral that is subject to liens held by any Common Security Agent or any Secured Debt Representative for the benefit of more than one class of Secured Obligations (such Collateral, "Shared Collateral") for any Second Priority Obligations; (ii) exercise or seek to exercise, or be entitled to direct (or instruct the Intercreditor Agent to direct) any Common Security Agent to exercise, any rights or remedies (including set-off) with respect to any Collateral subject to any lien in favor or a Common Security Agent or Secured Debt Representative for the benefit of Senior Priority Secured Parties (such Collateral, "Senior Priority Collateral") in respect of any Second Lien Obligations, or institute any action or proceeding with respect to such rights or remedies including, without limitation, under any lockbox agreement, control agreement, escrow agreement, letter of undertaking or similar agreement or arrangement entered into in connection with the Shared Collateral to which any Senior Priority Representative or Senior Priority Secured Party either is a party or may have rights as a third party beneficiary, or institute any action or proceeding with respect to such rights or remedies (including any action of foreclosure); (iii) effect or give instructions to effect any distressed disposition; (iv) contest, protest or object (or be entitled to direct (or instruct the Intercreditor Agent to direct) any Common Security Agent to contest, protest or object) to any foreclosure proceeding or other action brought with respect to the Senior Priority Collateral by any Common Security Agent, any Senior Priority Representative or any Senior Priority Secured Party in respect of the Senior Priority Obligations, the exercise of any right by any Security Agent or any Senior Priority Secured Party (or any agent or sub-agent on their behalf) in respect of the Senior Priority Obligations under any lockbox agreement, control agreement, landlord waiver or bailee's letter or similar agreement or arrangement to which any Common Security Agent, any Senior Priority Representatives or any Senior Priority Secured Party either is a party or may have rights as a third party beneficiary, or any other exercise by any such party of any rights and remedies relating to the Senior Priority Collateral under the Senior Priority Debt Documents or otherwise in respect of the Senior Priority Collateral or the Senior Priority Obligations; or (v) object (or be entitled to direct (or instruct the Intercreditor Agent to direct) any Common Security Agent to object) to the forbearance by the Senior Priority Secured Parties from bringing or pursuing any foreclosure proceeding or action or any other exercise of any rights or remedies relating to the Senior Priority Collateral in respect of Senior Priority Obligations.

Until the discharge of the Senior Priority Obligations, the Senior Priority Representative shall have the exclusive right to exercise, and/or to instruct the Intercreditor Agent to direct any Common Security Agent to exercise, any right or remedy with respect to the Senior Priority Collateral and shall have the exclusive right to determine and direct the time, method and place for exercising such right or remedy or conducting any proceeding with respect thereto.

Subject to whether or not any insolvency event has occurred or any insolvency or liquidation proceeding has been commenced by or against any Debtor, and subject as described below, the Senior Priority Representatives and the Senior Priority Secured Parties shall have the exclusive right to commence or maintain any enforcement action with respect to the Shared Collateral, and to instruct the Intercreditor Agent to direct the Common Security Agents or otherwise to enforce rights, exercise any rights or remedies (including set-off, recoupment and the right to credit bid their debt) and make determinations regarding the release, disposition or restrictions with respect to the Collateral without any consultation with or the consent of any Second Priority Secured Party and regardless of whether any such action is adverse to the interest of any Second Priority Secured Party or other party to the Senior Lien Intercreditor Agreement, and shall have the exclusive right to determine and direct the time, method and place for exercising such right or remedy or conducting any proceeding with respect thereto.

Further, each Junior Secured Representative, for itself and on behalf of each relevant Junior Secured Party (a) agrees that it will not take any action that would hinder, delay or otherwise interfere with any exercise of remedies undertaken by any Senior Priority Representative or any Senior Priority Secured Party, or any Common Security Agent on its or their behalf, with respect to the Senior Priority Collateral under the Senior Priority Debt Documents, including any disposition of the Senior Priority Collateral, whether by foreclosure or otherwise, (b) waives, to the fullest extent permitted by law, any and all rights it or any such Junior Secured Party may have as a junior lien creditor or unsecured creditor (other than exercise of rights as an unsecured creditor not prohibited by the Senior Lien Intercreditor Agreement) to (x) object to the manner in which the Senior Priority Representatives or the Senior Priority Secured Parties, or any Common Security Agent on its or their behalf, seek to enforce or collect the Senior Priority Obligations or the liens granted on any of the Shared Collateral, regardless of whether any action or failure to act by or on behalf of any Senior Priority Representative or any other Senior Priority Secured Party is adverse to the interests of such Secured Parties or (y) demand, request, plead or otherwise assert or claim the benefit of any marshalling, appraisal, valuation or other similar right that may be available under applicable law with respect to the Senior Priority Collateral or the Shared Collateral or any similar rights a junior secured creditor may have under applicable law, and (c) agrees that it will not commence, or join with any person (other than the Senior Priority Secured Parties and the Senior Priority Representatives or the Intercreditor Agent, in each case upon the request of the Relevant Designated Representative, or any Common Security Agent upon the request of the Intercreditor Agent) in commencing, any enforcement, collection, execution, levy or foreclosure action or proceeding with respect to any lien held by it in the Senior Priority Collateral under any of the Junior Secured Debt Documents or otherwise in respect of the Junior Secured Obligations.

Notwithstanding the restrictions described above: (i) in any insolvency or liquidation proceeding commenced by or against any Debtor, any Second Priority Representative may file a claim, proof of claim, or statement of interest with respect to the relevant Second Priority Obligations in a manner that is consistent with the terms and conditions of the Senior Lien Intercreditor Agreement; (ii) any Second Priority Representative may take any action (not adverse to the prior liens on the Senior Priority Collateral or the rights of the Common Security Agents, the Senior Priority Representatives or the Senior Priority Secured Parties to exercise remedies in respect thereof) in order to create, prove, perfect, preserve or protect (but not enforce) its rights in, and perfection and priority of its lien on, the Shared Collateral; (iii) any Second Priority Representative and the Second Priority Secured Parties may exercise their rights and remedies as unsecured creditors, subject to certain provisos; (iv) any Second Priority Representative may file a proof of claim or statement of interest with respect to the applicable Secured Obligations and the Second Priority Secured Parties may file any responsive or defensive pleadings in opposition to any motion or pleading seeking the disallowance of the claims of the applicable Junior Secured Party, to the extent not otherwise in contravention of the terms of the Senior Lien Intercreditor Agreement or credit bid to the extent permitted under the Senior Lien Intercreditor Agreement, and the Second Priority Secured Parties may file any responsive or defensive pleadings in opposition to any motion, claim, adversary proceeding or other pleading made by any person seeking disallowance, which is not permitted by the Senior Lien Intercreditor Agreement, of the claims or liens of the Second Priority Secured Parties or the avoidance of any liens in respect of Junior Secured Obligations to the extent not inconsistent with the terms of the Senior Lien Intercreditor Agreement; (v) any Second Priority Secured Party may vote on any plan of reorganization, plan of liquidation, agreement for composition, or other type of plan of arrangement proposed in or in connection with any insolvency event or any insolvency or liquidation proceeding that conforms to the terms and conditions of the Senior Lien Intercreditor Agreement (provided that a Junior Secured Party (whether in the capacity of a secured creditor or an unsecured creditor)) may propose, vote in favor of, or otherwise directly or indirectly support any plan of reorganization, plan of liquidation, agreement for composition, or other type of plan of arrangement that violates the priorities or other provisions of the Senior Lien Intercreditor Agreement if such plan (a) pays off, in cash in full, all Senior Priority Obligations or (b) is accepted by the class of holders of the Senior Priority Obligations voting thereon in accordance with Section 1126(c) of the Bankruptcy Code); (vi) from and after the applicable Second Priority Enforcement Date, the Second Priority Representative (or any other person authorized under any applicable pari passu intercreditor agreement with respect to the relevant class of Secured Obligations, as applicable) may exercise any rights or remedies (including set-off) with respect to any Senior Priority Collateral in respect of any Senior Priority Obligations, or institute any action or proceedings with respect to such rights or remedies (including any action of foreclosure), but only so long as (1) a Senior Priority Representative has not commenced or instructed (through the Intercreditor Agent) any Common Security Agent and is not diligently pursuing any enforcement action with respect to a material portion of Senior Priority Collateral or (2) no insolvency event has occurred and no insolvency or liquidation proceeding has been commenced by or against any Debtor; (vii) the Second Priority Secured Parties shall have the right to credit bid at any private or judicial foreclosure sale of Senior Priority Collateral, so long as any such credit bid provides for the indefeasible payment in full in cash of the Senior Priority Obligations; and (viii) the Secured Debt Representatives shall be permitted to take acceleration action in accordance with the applicable Secured Debt Documents.

Prior to the discharge of the Senior Priority Obligations, if any Junior Secured Representative or any Junior Secured Party receives any Shared Collateral or proceeds of the Shared Collateral in contravention of the order of priority set out in the Senior Lien Intercreditor Agreement, such Collateral or proceeds must be segregated and held in trust for and on behalf of the Senior Priority Secured Parties and paid over to the Senior Priority Representative for application against the Senior Priority Obligations.

Release of Liens on Collateral

Pursuant to the Senior Lien Intercreditor Agreement, until the discharge of Senior Priority Obligations, in the event of any disposition of any specified item of Shared Collateral (i) in connection with the exercise of any rights or remedies (including any enforcement action) in respect of Shared Collateral by the Relevant Designated Representative or any Common Security Agent on its behalf or at the direction of the Intercreditor Agent (at the direction of the Relevant Designated Representative), (ii) pursuant to Section 363 of the Bankruptcy Code or (iii) at any time when the Shared Collateral has become enforceable after the occurrence of an acceleration action, the applicable Common Security Agent (upon prior instruction from the Intercreditor Agent) is irrevocably authorized and instructed to release (i)(x)(1) the liens granted to the Senior Priority Representatives and Senior Priority Secured Parties, or any Common Security Agent on its or their behalf, upon such Shared Collateral, or (2) any member of the Group from its obligations under any Senior Priority Debt Document and (y)(1) the liens granted to the Junior Secured Representatives and Junior Secured Parties, or any Common Security Agent on its or their behalf, upon such Shared Collateral (but not on the Proceeds thereof that were not applied to the payment of Senior Priority Obligations) to secure Junior Secured Obligations, or (2) any member of the Group from its obligations under any Junior Secured Debt Documents, and the applicable Common Security Agent is irrevocably authorized and instructed to execute and deliver or enter into any release of such liens, or guarantee that may be necessary or desirable in connection with such releases and to issue any letters of non-crystallization of any floating charge or any consent to dealing that may be necessary or desirable; provided, that, with respect to any release in connection with the exercise of any rights or remedies (including any collateral enforcement action) in respect of Shared Collateral by the Relevant Designated Representative or any Common Security Agent on its behalf or at the direction of the Intercreditor Agent (acting at the direction of such Relevant Designated Representative), the proceeds of any such collateral enforcement action or other disposition are applied in accordance with the proceeds waterfall and (ii) if the asset that is the subject of a disposition consists of shares in the capital of a member of the Group as applicable and the applicable Common Security Agent is instructed by the Intercreditor Agent to transfer to another member of the Group all or any part of the disposed entity's obligations or any obligations of any subsidiary of that disposed entity in respect of Senior Priority Obligations, to dispose of such obligations in respect of such Senior Priority Obligations and to execute and deliver or enter into any agreement to (x) agree to the transfer of all or part of the obligations in respect of such Senior Priority Obligations on behalf of the Senior Priority Secured Parties, as the case may be, to which those obligations are owed and on behalf of the obligors that owe those obligations and (y) accept the transfer of all or part of the obligations in respect of such Senior Priority Obligations on behalf of the entity to which the obligations in respect of such Senior Priority Obligations are to be transferred.

In connection with any non-distressed disposal of any Shared Collateral by any Debtor permitted under the terms of the Senior Priority Debt Documents and the Second Lien Debt Documents, each Common Security Agent (upon prior instructions of and direction from the Intercreditor Agent) is irrevocably authorized and instructed (upon receipt of an officer's certificate by the applicable Debtor certifying that such release is permitted by the terms of the Senior Lien Intercreditor Agreement and the relevant Secured Debt Documents) to release any liens on any part of the Shared Collateral that is the subject of such disposal other than after the occurrence of an enforcement action.

Purchase right

Within 30 days of any (a) acceleration action in respect of all of the Borrowing Base Obligations or all of the Senior Secured Obligations, as applicable, or the commencement of an enforcement action in respect of the members of the Group or the Collateral, (b) commencement of insolvency or liquidation proceeding or the occurrence of an insolvency event, (c) occurrence of a non-payment event of default in respect of the principal, interest or fees (other than agency fees) under any Borrowing Base Debt Document or Senior Secured Debt Document, as applicable, that is not waived within 60 days, or (d) exercise of remedies by any Borrowing Base Representative or any other Borrowing Base Secured Party or any Senior Secured Representative or by any other Senior Secured Party, as applicable, or in each case the Common Security Agents on its or their behalf against the Debtors or the Collateral (not including the activation of springing control agreements regarding deposit accounts without application to and permanent reduction of the revolving commitments), one or more Second Lien Secured Parties may request to purchase all, but not less than all, of the outstanding Borrowing Base Obligations or all, but not less than all, of the outstanding Senior Secured Obligations, as applicable, at par, plus any applicable prepayment premium and any accrued and unpaid interest, fees and expenses. If this right is exercised, the parties must endeavor to complete the sale and transfer within 10 business days of the request.

Insolvency or Liquidation Proceedings

The Senior Lien Intercreditor Agreement provides that, prior to the discharge of Senior Priority Obligations, in any insolvency or liquidation proceedings of a Debtor:

(1) if the Senior Priority Representative desires to consent (or not object) to the sale, use or lease of cash or other Collateral or to consent (or not object) to any Debtor's obtaining financing under Section 362, 363 or 364 of the Bankruptcy Code or any similar provision of any other debtor relief law ("DIP Financing"), then no Junior Secured Party will raise any objection to such sale, use or lease of such cash or other Collateral or such DIP Financing or request adequate protection or any other relief in connection therewith (except to the extent otherwise permitted by the Senior Lien Intercreditor Agreement) and, to the extent the liens securing the Senior Priority Obligations are subordinated to or *pari passu* with the liens securing such DIP Financing, each Junior Secured Party will subordinate its liens in the Shared Collateral to (x) such DIP Financing (and all obligations relating thereto), (y) any "carve-out" for professional and United States trustee fees agreed to by the Senior Priority Representatives, and (z) all adequate protection liens granted to the Senior Priority Secured Parties;

(2) no Junior Secured Party will raise any objection to or otherwise contest (i) any motion for relief from the automatic stay or any other stay in any insolvency or liquidation proceedings or from any injunction against foreclosure or enforcement in respect of Senior Priority Obligations or the Senior Priority Collateral made by any Senior Priority Representative or any other Senior Priority Secured Party, (ii) any lawful exercise by any Senior Priority Secured Party of the right to credit bid Senior Priority Obligations at any foreclosure or other sale of Senior Priority Collateral, including pursuant to Section 363(k) of the Bankruptcy Code or any similar provision of any other applicable law, (iii) any other request for judicial relief made in any court by any Senior Priority Secured Party relating to the lawful enforcement of any lien on Senior Priority Collateral, (iv) any election made

by any Senior Priority Representative or any other Senior Priority Secured Party of the application of Section 1111(b) of the Bankruptcy Code or any similar provision of any other debtor relief law with respect to any of the Shared Collateral; or (v) any disposition (including pursuant to Section 363 of the Bankruptcy Code or any similar provision of any other similar debtor relief law) of assets of any Debtor to which any Senior Priority Representative has consented or not objected; provided that, to the extent such disposition is to be free and clear of liens, the liens securing the Senior Priority Obligations, the Senior Secured Obligations and the Second Lien Obligations will attach to the proceeds of the sale on the same basis of priority as the liens on the Shared Collateral securing the Senior Priority Obligations rank to the liens on the Shared Collateral securing the Secured Obligations pursuant to the Senior Lien Intercreditor Agreement; and

(3) no Second Lien Secured Party shall seek relief from the automatic stay or any other stay or take any action in derogation thereof, in each case in respect of any Shared Collateral, without the prior written consent of the Relevant Designated Representative.

Prior to the discharge of the Borrowing Base Obligations, the Borrowing Base Secured Parties shall have the exclusive right to offer to and to provide, administer or syndicate DIP Financing to any Debtor for 60 days after an acceleration action or enforcement action, provided that if no Borrowing Base Secured Party offers to provide any DIP Financing during that 60-day period, the Junior Secured Parties may propose DIP Financing consistent with the requirements for DIP Financing otherwise set forth in the Senior Lien Intercreditor Agreement (subject to the right of the Borrowing Base Secured Parties to participate pro rata in such DIP Financing).

The Senior Lien Intercreditor Agreement provides that no Junior Secured Party shall object to, contest or support any other person objecting to or contesting (a) any request by any Senior Priority Representative, Senior Priority Secured Parties or any Common Security Agent for adequate protection in any form, (b) any objection by any Senior Priority Representative, Senior Priority Secured Parties or any Common Security Agent to any motion, relief, action or proceeding based on any Senior Priority Representative's, Senior Priority Secured Party's or Common Security Agent's claiming a lack of adequate protection or (c) the allowance and/or payment of pre- and/or post-petition interest, fees, expenses or other amounts of any Senior Priority Representative, Senior Priority Secured Party or Common Security Agent under Section 506(b) or 506(c) of the Bankruptcy Code or any similar provision of any other debtor relief law (as adequate protection or otherwise).

Notwithstanding the foregoing, in any insolvency or liquidation proceeding or another insolvency event, (i) if the Senior Priority Secured Parties (or any subset thereof) are granted adequate protection in the form of a lien on additional or replacement collateral and/or superpriority claims in connection with any DIP Financing or use of cash collateral under Section 363 or 364 of the Bankruptcy Code or any similar provision of any other debtor relief law, then each Junior Secured Representative, for itself and on behalf of each Junior Secured Party that it represents, may seek or request adequate protection in the form of a lien on such additional or replacement collateral and/or a superpriority claim (as applicable), which Lien and/or superpriority claim (as applicable) is subordinated to the liens securing, and claims with respect to, all Senior Priority Obligations and such DIP Financing and any other liens or claims granted to the Senior Priority Secured Parties as adequate protection, on the same basis as the other liens securing, and claims with respect to, the other Obligations are so subordinated to the liens securing, and claims with respect to, Senior Priority Obligations under the Senior Lien Intercreditor Agreement; and (ii) if any Junior Secured Representatives, for themselves and on behalf of any Junior Secured Parties that they represent, seek or request adequate protection and such adequate protection is granted (in each instance, to the extent such grant is otherwise permissible under the terms and conditions of the Senior Lien Intercreditor Agreement) in the form of a lien on additional or replacement collateral and/or a superpriority claim, then each Senior Priority Representative, for themselves and on behalf of each Senior Priority Secured Party that they represent, shall also be granted a senior lien on such additional or replacement collateral as security and adequate protection for the Senior Priority Obligations and any such DIP Financing and/or a superpriority claim (as applicable) and any lien on such additional or replacement collateral securing or providing adequate protection for the relevant Obligations and/or superpriority claim (as applicable) shall be subordinated to the liens on such collateral securing the Senior Priority Obligations and any such DIP Financing (and all obligations relating thereto) and to any other Liens or claims granted to the Senior Priority Secured Parties as adequate protection on the same basis as the other liens securing, and claims with respect to, the relevant Obligations are so subordinated to such liens securing, and claims with respect to, Senior Priority Obligations under the Senior Lien Intercreditor Agreement.

The Senior Lien Intercreditor Agreement provides that if any Senior Priority Secured Party is required in any insolvency or liquidation proceeding or other insolvency event or otherwise to turn over or otherwise pay any amount to the estate of any Debtor (or any trustee, receiver, monitor, receiver-manager or similar person), because the payment of such amount was declared to be fraudulent or preferential or for any other reason (any such amount, a "**Recovery**"), then Senior Priority Obligations shall be reinstated to the extent of the Recovery. If the Senior Lien Intercreditor Agreement is terminated prior to such Recovery, the Senior Lien Intercreditor Agreement will be reinstated in full force and effect, and such prior termination shall not diminish, release, discharge, impair or otherwise affect the obligations of the parties from such date of reinstatement.

The Senior Lien Intercreditor Agreement provides that the grants of liens pursuant to the Senior Priority Collateral Documents and the Junior Secured Collateral Documents constitute separate and distinct grants of liens; and because of, among other things, their differing rights in the Shared Collateral, the Junior Secured Obligations are fundamentally different from the Senior Priority Obligations and must be separately classified in any plan of reorganization proposed or adopted in an insolvency or liquidation proceeding or other insolvency event. If it is held that the claims of the Senior Priority Secured Parties and the Junior Secured Parties in respect of the Shared Collateral constitute only one secured claim (rather than separate classes of senior and junior secured claims), then all distributions will be made as if there were separate classes of senior and junior secured claims against the Debtors in respect of the Shared Collateral (with the effect being that, to the extent that the aggregate value of the Shared Collateral is sufficient (for this purpose ignoring all claims held by the Junior Secured Parties), the Senior Priority Secured Parties shall be entitled to receive, in addition to amounts distributed to them in respect of principal, pre-petition interest, fees and expenses and other claims, all amounts owing in respect of post-petition interest, fees, and expenses (whether or not allowed or allowable under Section 506(b) of the Bankruptcy Code (or any similar provision of any other debtor relief law) or otherwise in such insolvency or liquidation proceeding or another insolvency event) before any distribution from the Shared Collateral is made in respect of the Junior Secured Obligations. Each Junior Secured Representative, for itself and on behalf of the Junior Lien Secured Parties for whom it acts as representative, agrees to turn over to the Senior Priority Representative amounts otherwise received or receivable by them to the extent necessary to effectuate the intent of this sentence, even if such turnover has the effect of reducing the claim or recovery of the Junior Secured Parties).

Nothing in the Senior Lien Intercreditor Agreement, except as expressly provided therein, prohibits or in any way limits any Senior Priority Secured Party from objecting in any insolvency or liquidation proceeding or other insolvency event or otherwise to any action taken by any Junior Secured Party, including the seeking by any Junior Secured Party of adequate protection or the asserting by any Junior Secured Party of any of its rights and remedies under the Secured Debt Documents or otherwise.

The Senior Lien Intercreditor Agreement provides that if, in any insolvency or liquidation proceeding, any distribution of debt obligations or equity securities is made by a reorganized debtor pursuant to a plan of reorganization or other type of plan of arrangement, both on account of the Senior Priority Obligations and the other Obligations (such debt obligations or equity securities, the "Reorganization Securities"), each of the Secured Parties shall be entitled to receive and retain such Reorganization Securities, provided, that (i) to the extent the debt obligations distributed on account of the Senior Priority Obligations and on account of the other Obligations are secured by liens upon the same assets or property, the provisions of the Senior Lien Intercreditor Agreement will survive the distribution of such debt obligations pursuant to such plan and will apply with like effect to the liens securing such debt obligations and (ii) to the extent the Reorganization Securities consist of equity securities, and the discharge of the Senior Priority Obligations does not occur, then the Junior Secured Parties shall be required to pay over to the Senior Priority Representative any equity securities so received.

The Senior Lien Intercreditor Agreement provides that no Junior Secured Party (whether in the capacity of a secured creditor or an unsecured creditor) shall propose, vote in favor of, or otherwise support any plan of reorganization, plan of liquidation, agreement for composition, or other type of plan of arrangement that violates the priorities or other provisions of the Senior Lien Intercreditor Agreement unless such plan (a) pays off, in cash in full, all Senior Priority Obligations or (b) is accepted by the class of holders of the Senior Priority Obligations voting thereon in accordance with Section 1126(c) of the Bankruptcy Code.

Additional and/or refinancing debt

The Senior Lien Intercreditor Agreement provides that, to the extent permitted by the provisions of the Senior Priority Debt Documents and the Second Lien Debt Documents then in effect, any Debtor may incur or issue and sell one or more series or classes of secured indebtedness that is *pari passu* with the Second Lien Obligations, and/or one or more series or classes of secured indebtedness that is *pari passu* with the Senior Secured Obligations, provided the representative of any such indebtedness (as applicable) becomes a party to the Senior Lien Intercreditor Agreement.

The Senior Lien Intercreditor Documents include provisions requiring the Debtors, Secured Debt Representatives and Secured Parties to take actions reasonably requested, and subject to the terms of the Senior Lien Intercreditor Documents, facilitate the incurrence of refinancing and/or additional Secured Obligations that are permitted to be incurred pursuant to the Secured Debt Documents and the sharing in Collateral with respect thereto.

Governing law

The Senior Lien Intercreditor Documents are governed by English law.

Definitions

For purposes of this description of the Senior Lien Intercreditor Documents, the defined terms set out below shall have the following meanings as used in this section:

"Borrowing Base Collateral Documents" means the Common Borrowing Base Collateral Documents and each of the collateral agreements, security agreements and other instruments and documents executed and delivered by any Borrowing Base Obligor or any other Debtor creating or purporting to create any lien on any Collateral to secure the Borrowing Base Obligations.

"Borrowing Base Guarantor" means (a) on or prior the discharge of Borrowing Base Obligations, a "Borrowing Base Guarantor" as defined in the RBL facility and (b) after the discharge of Borrowing Base Obligations, any Borrowing Base Obligor that provides a guarantee, indemnity or assurance against loss with respect to any Borrowing Base Obligations and/or other Obligations.

"Borrowing Base Secured Parties" means the Intercreditor Agent, the holders of Borrowing Base Obligations, the Borrowing Base Representative, any trustee or agent therefor under any related Borrowing Base Debt Documents and the beneficiaries of each indemnification obligation undertaken by any borrower or any guarantor under any related Borrowing Base Debt Documents.

"Collateral" means all assets and property subject to a lien under any Collateral Document to secure any of the Secured Obligations.

"Collateral Documents" means the Common Collateral Documents and any other Borrowing Base Collateral Documents, any other Senior Secured Collateral Documents and any other Second Lien Collateral Documents.

"Common Borrowing Base Collateral Documents" means certain documents specified as such in the Security Agency and Subordination Deed and each of the collateral agreements, security agreements and other instruments and documents executed and delivered by any Borrowing Base Obligor or any other Debtor creating or purporting to create any lien on any Borrowing Base Priority Collateral in favor of a Common Security Agent to secure the Borrowing Base Obligations and any other Secured Obligations of any class(es) or series.

"Common Collateral Documents" means the Common Borrowing Base Collateral Documents and the Common Corporate Collateral Documents.

"Common Corporate Collateral Documents" means certain documents specified as such in the Security Agency and Subordination Deed and each of the collateral agreements, security agreements and other instruments and documents executed and delivered by any Corporate Debtor creating or purporting to create any lien on any Collateral (other than Borrowing Base Priority Collateral) in favor of a Common Security Agent to secure any Secured Obligations of any class(es) or series.

"Group" means the Parent Guarantor and each of its Subsidiaries.

"Obligations" means the Borrowing Base Obligations, Senior Secured Obligations and Second Lien Obligations.

"Second Lien Pari Passu Intercreditor Agreement" means that certain Second Lien Pari Passu Intercreditor Agreement, in the form to be attached to the indenture, by and among the Trustee and each of the other parties from time to time party thereto, and acknowledged and agreed to by the Issuer and the other grantors from time to time party thereto, as may be amended, restated, supplemented or otherwise modified from time to time in accordance with its terms and in accordance with the indenture.

"Second Lien Collateral Documents" means the Common Collateral Documents and each of the collateral agreements, security agreements and other instruments and documents executed and delivered by any Corporate Debtor or any other Debtor creating or purporting to create any lien on any Collateral to secure any Second Lien Obligations.

"Second Lien Debt Documents" means with respect to any series, issue or class of second lien debt, the promissory notes, credit agreements, loan advances, note purchase agreements, indentures or other operative agreements evidencing or governing such indebtedness or the liens securing such indebtedness, including the Second Lien Collateral Documents.

"Second Lien Enforcement Date" means, with respect to any Second Lien Representative, the date that is 180 calendar days (through which 180-day period such Second Lien Representative was the Designated Second Lien Representative) after the occurrence of both (i) an Event of Default (under and as defined in the Second Lien Debt Document for which such Second Lien Representative has been named as representative) and (ii) the Relevant Designated Representative's and each Junior Secured Representative's receipt of written notice from such Second Lien Representative that such Second Lien Representative is the Designated Second Lien Representative and that an Event of Default (under and as defined in the Second Lien Debt Document for which such Second Lien Representative has been named as representative) has occurred and is continuing; provided that the Second Lien Enforcement Date shall be stayed and shall not occur and shall be deemed not to have occurred (1) at any time a Senior Priority Representative has commenced and is diligently pursuing any collateral enforcement action with respect to a material portion of any Shared Collateral or (2) at any time any Debtor that has granted a security interest in any Shared Collateral is then a debtor under or with respect to (or otherwise subject to) any insolvency, liquidation proceeding or insolvency event.

"Second Lien Secured Parties" means, with respect to any series, issue or class of indebtedness that is *pari passu* with Second Lien Obligations, the holders of such indebtedness or any other Second Lien Obligation, the representative with respect thereto, any trustee or agent therefor under any related Second Lien Debt Documents and the beneficiaries of each indemnification obligation undertaken by any borrower or any guarantor under any related Second Lien Debt Documents.

"Second Priority Enforcement Date" means (a) when the Senior Secured Representative is the Second Priority Representative, the Senior Secured Enforcement Date and (b) when the Second Lien Representative is the Second Priority Representative, the Second Lien Enforcement Date.

"Second Priority Obligations" means (a) with respect to the Borrowing Base Priority Collateral (i) prior to the discharge of the Borrowing Base Obligations, (A) the Senior Secured Obligations (unless no Senior Secured Obligations have been incurred) and (B) following the discharge of Senior Secured Obligations or if no Senior Secured Obligations have been incurred, the Second Lien Obligations and (ii) following the discharge of the Borrowing Base Obligations and prior to the discharge of the Senior Secured Obligations (unless no Senior Secured Obligations have been incurred), the Second Lien Obligations and (b) with respect to the Corporate Collateral, the Second Lien Obligations.

"Second Priority Representative" means (a) with respect to the Borrowing Base Priority Collateral, (i) prior to the discharge of the Borrowing Base Obligations, (A) the Senior Secured Representative (unless no Senior Secured Obligations have been incurred) and (B) following the discharge of Senior Secured Obligations or if no Senior Secured Obligations have been incurred, the Second Lien Representative and (ii) following the discharge of the Borrowing Base Obligations but prior to the discharge of the Senior Secured Obligations (unless no Senior Secured Obligations have been incurred), the Second Lien Representative and (b) with respect to the Corporate Collateral, the Second Lien Representative.

"Second Priority Secured Parties" means (a) with respect to the Borrowing Base Priority Collateral, (i) prior to the discharge of the Borrowing Base Obligations, (A) the Senior Secured Parties (unless no Senior Secured Obligations have been incurred) and (B) following the discharge of Senior Secured Obligations or if no Senior Secured Obligations have been incurred, the Second Lien Secured Parties and (ii) following the discharge of the Borrowing Base Obligations but prior to the discharge of the Senior Secured Obligations (unless no Senior Secured Obligations have been incurred), the Second Lien Secured Parties and (b) with respect to the Corporate Collateral, the Second Lien Secured Parties.

"Secured Debt Representatives" means the Borrowing Base Representative, the Second Lien Representatives and the Senior Secured Representatives.

"Senior Priority Debt Documents" means (a) with respect to the Borrowing Base Priority Collateral, (i) prior to the discharge of the Borrowing Base Obligations, the Borrowing Base Debt Documents and (ii) following the discharge of the Borrowing Base Obligations and prior to the discharge of the First Lien Obligations, the Senior Secured Debt Documents (unless no Senior Secured Obligations have been incurred) and (iii) following the discharge of the First Lien Obligations and prior to the discharge of the Second Lien Obligations, the Second Lien Debt Documents and (b) with respect to the Corporate Collateral, (i) prior to the discharge of the First Lien Obligations, the First Lien Debt Documents and (ii) following the discharge of the First Lien Obligations and prior to the discharge of the Second Lien Obligations, the Second Lien Debt Documents.

"Senior Priority Obligations" means (a) with respect to the Borrowing Base Priority Collateral or guarantee claims against Borrowing Base Guarantors (i) prior to the discharge of the Borrowing Base Obligations, the Borrowing Base Obligations and (ii) following the discharge of the Borrowing Base Obligations and prior to the discharge of the First Lien Obligations, the Senior Secured Obligations (unless no Senior Secured Obligations have been incurred) and (iii) following the discharge of the First Lien Obligations and prior to the discharge of the Second Lien Obligations, the Second Lien

Obligations and (b) with respect to the Corporate Collateral or guarantee claims against Corporate Debtors (as defined in the RBL facility) (i) prior to the discharge of the First Lien Obligations, the First Lien Obligations and (ii) following the discharge of the First Lien Obligations and prior to the discharge of the Second Lien Obligations, the Second Lien Obligations, in each case excluding any obligations the incurrence of which was not permitted, at the time of such incurrence, in accordance with the terms of the Borrowing Base Debt Documents, Senior Secured Debt Documents or Second Lien Debt Documents.

"Senior Priority Representative" means (a) with respect to the Borrowing Base Priority Collateral, (i) prior to the discharge of the Borrowing Base Obligations, the Borrowing Base Representative and (ii) following the discharge of the Borrowing Base Obligations and prior to the discharge of the First Lien Obligations, the Senior Secured Representative (unless no Senior Secured Obligations have been incurred) and (iii) following the discharge of the First Lien Obligations and prior to the discharge of the Second Lien Obligations, the Second Lien Representative and (b) with respect to the Corporate Collateral, (i) prior to the discharge of the First Lien Obligations, the First Lien Representative and (ii) following the discharge of the First Lien Obligations and prior to the discharge of the Second Lien Obligations, the Second Lien Representative.

"Senior Priority Secured Parties" means (a) with respect to the Borrowing Base Priority Collateral, (i) prior to the discharge of the Borrowing Base Obligations, the Borrowing Base Secured Parties and (ii) following the discharge of the Borrowing Base Obligations and prior to the discharge of the First Lien Obligations, the Senior Secured Parties (unless no Senior Secured Obligations have been incurred) and (iii) following the discharge of the First Lien Obligations and prior to the discharge of the Second Lien Obligations, the Second Lien Secured Parties and (b) with respect to the Corporate Collateral, (i) prior to the discharge of the First Lien Obligations, the First Lien Secured Parties and (ii) following the discharge of the First Lien Obligations and prior to the discharge of Second Lien Obligations, the Second Lien Secured Parties.

"Senior Secured Collateral Documents" means the Common Collateral Documents and each of the collateral agreements, security agreements and other instruments and documents executed and delivered by any Corporate Debtor or any other Debtor creating or purporting to create any lien on any Collateral to secure any Senior Secured Obligations.

"Senior Secured Enforcement Date" means, with respect to any Senior Secured Representative, the date that is 180 calendar days after the occurrence of both (i) an Event of Default (under and as defined in the Senior Secured Debt Document for which such Senior Secured Representative has been named as representative) and (ii) the Relevant Designated Representative's and each Junior Secured Representative's receipt of written notice from such Senior Secured Representative that such Senior Secured Representative is the Senior Secured Representative (in the case of a Common Security Agent, as notified by the Intercreditor Agent) and that an Event of Default (under and as defined in the Senior Secured Debt Document for which such Senior Secured Representative has been named as representative) has occurred and is continuing; provided that the Senior Secured Enforcement Date shall be stayed and shall not occur and shall be deemed not to have occurred (1) at any time a Senior Priority Representative has commenced and is diligently pursuing any collateral enforcement action with respect to a material portion of any Shared Collateral or (2) at any time any Debtor that has granted a security interest in any Shared Collateral is then a debtor under or with respect to (or otherwise subject to) any insolvency or liquidation proceeding or an insolvency event.

"Senior Secured Parties" means the Intercreditor Agent and, with respect to any series, issue or class of Senior Secured Debt, the holders of such indebtedness or any other Senior Secured Obligation, the representative with respect thereto, any trustee or agent therefor under any related Senior Secured Debt Documents and the beneficiaries of each indemnification obligation undertaken by any borrower or any guarantor under any related Senior Secured Debt Documents.

Second Lien Pari Passu Intercreditor Agreement

The indenture will provide that the Issuer, the Guarantors and the Trustee (as the 2024 Second Lien Representative) will be authorized, and directed, in the case of the Trustee, without any further consent of the holders of Notes, to enter into the Second Lien Pari Passu Intercreditor Agreement with any Initial Other Second Lien Representative, the Offshore Security Agent and the Onshore Security Agent in connection with the incurrence of any other series of pari passu second-priority obligation served by collateral that is required to be subject thereto. The indenture will provide that it will be subject to the terms of such Second Lien Pari Passu Intercreditor Agreement.

The Second Lien Pari Passu Intercreditor Agreement will set forth the terms of the relationship between the Trustee, on behalf of the 2024 Indenture Claimholders, and the Initial Other Second Lien Representative, on behalf of the Initial Other Second Lien Claimholders, with respect to the Shared Collateral, the priority of the Second Lien Claimholders, the administration and enforcement of the Second Lien Obligations, the application of proceeds from the Shared Collateral, actions with respect to bankruptcy proceedings and certain related matters.

The Indenture will also provide that each holder, by accepting the note, will be deemed to have:

(a) appointed, directed and authorized the Trustee to give effect to provisions of the Second Lien Pari Passu Intercreditor Agreement;

(b) authorized and directed the Trustee to become a party to the Second Lien Pari Passu Intercreditor Agreement;

(c) agreed to be bound by the provisions of the Second Lien Pari Passu Intercreditor Agreement, and any amendment permitted under "—Amendments and Waivers"; and

(d) irrevocably appointed the Trustee to act on its behalf to enter into and comply with the provisions of the Second Lien Pari Passu Intercreditor Agreement, and any amendment referred to above.

The Trustee shall not be required to seek the consent of any Holders to perform its obligations under, and in accordance with, this covenant.

Upon receipt by the Trustee of (a) an officer's certificate certifying, and an opinion of counsel opining (as to (i) and (iii)) that: (i) the Second Lien Pari Passu Intercreditor Agreement is authorized or permitted by the Indenture and complies with the provisions of the Indenture; (ii) all conditions precedent to the execution of the Second Lien Pari Passu Intercreditor Agreement have been satisfied; and (iii) the Second Lien Pari Passu Intercreditor Agreement will be, upon the date the Second Lien Pari Passu Intercreditor Agreement, made effective pursuant to the indenture, the legal, valid and binding obligation of the Issuer (and any Guarantor) enforceable against them in accordance with its terms, and (b) an issuer order, which may be part of the Officer's Certificate, to enter into the Second Lien Pari Passu Intercreditor Agreement and documents related thereto, the Trustee shall enter into the Second Lien Pari Passu Intercreditor Agreement and such other documentation as may be necessary or desirable to give effect to the Second Lien Pari Passu Intercreditor Agreement, provided that (x) the Trustee shall not be required to enter into the Second Lien Pari Passu Intercreditor Agreement and any such other documentation that will impose any personal obligations on the Trustee or adversely affect the rights, duties, obligations, liabilities, protections, indemnities or immunities of the Trustee under the indenture or the Second Lien Pari Passu Intercreditor Agreement (other than rights, duties or obligation contemplated hereby) and (y) the Trustee shall be indemnified (and shall also be entitled to request security and/or pre-funding) by the Issuer to its satisfaction in a manner consistent with the indenture and the Senior Lien Intercreditor Documents.

For purposes of this description of the Second Lien Pari Passu Intercreditor Agreement, the defined terms set out below shall have the following meanings as used in this section:

"2024 Indenture Claimholders" means the holders of any 2024 Indenture Obligations, including the "Secured Parties" as defined in the 2024 Indenture or in the 2024 Indenture Collateral Documents and the Trustee and 2024 Second Lien Collateral Agent.

"2024 Indenture Documents" means the Indenture, each security document securing the Notes and Guarantees (the "2024 Indenture Collateral Documents") Document and the other Notes Documents (as defined in the 2024 Indenture), and each of the other agreements, documents and instruments providing for or evidencing any other 2024 Indenture Obligation, as each may be amended, restated, amended and restated, supplemented or otherwise modified from time to time.

"2024 Indenture Obligations" means:

(a) the Note Obligations (as defined in the 2024 Indenture as in effect on the date of the Second Lien Pari Passu Intercreditor Agreement); and

(b) to the extent any payment with respect to any 2024 Indenture Obligation (whether by or on behalf of any Debtor, as proceeds of security, enforcement of any right of setoff or otherwise) is declared to be a fraudulent conveyance or a preference in any respect, set aside or required to be paid to a debtor in possession, any Other Second Lien Claimholder, receiver or similar Person, then the obligation or part thereof originally intended to be satisfied shall, for the purposes of this Agreement and the rights and obligations of the 2024 Indenture Claimholders and the Other Second Lien Claimholders, be deemed to be reinstated and outstanding as if such payment had not occurred. To the extent that any interest, fees, expenses or other charges (including Post-Petition Interest) to be paid pursuant to the 2024 Indenture Documents are disallowed by order of any court, including by order of a court of competent jurisdiction presiding over an Insolvency or Liquidation Proceeding, such interest, fees, expenses and charges (including Post-Petition Interest) shall, as between the 2024 Indenture Claimholders and the Other Second Lien Claimholders, be deemed to continue to accrue and be added to the amount to be calculated as the "2024 Indenture Obligations." 2024 Indenture Obligations shall include any Registered Equivalent Notes and Guarantees thereof by the Debtors issued in exchange therefor.

"2024 Second Lien Collateral Agent" means the collateral agent for the 2024 Indenture Claimholders, if any (in such capacity and together with its successors from time to time in such capacity).

"Additional Second Lien Representative" means with respect to each Series of Other Second Lien Obligations, that becomes subject to the terms of the Second Lien Pari Passu Intercreditor Agreement after the date thereof, the Person serving as administrative agent, facility agent, collateral agent, trustee or in a similar capacity for such Series of Other Second Lien Obligations and named as such in the applicable joinder agreement, together with its successors from time to time in such capacity.

"Applicable Collateral Agent" means, in respect of any particular Collateral, (a) if such Collateral is subject to Liens in favor of a Common Security Agent, such Common Security Agent or (b) if such Collateral is not subject to Liens in favor of a Common Security Agent, (i) until the Non-Controlling Representative Enforcement Date, the Second Lien Collateral Agent for the Series of Second Lien Obligations represented by the Major Controlling Representative and (ii) from and after the Non-Controlling Representative Enforcement Date, the Second Lien Collateral Agent for the Series of Second Lien Obligations represented by the Major Non-Controlling Representative.

"Bankruptcy Case" has the meaning set forth under the caption "—Second Lien Pari Passu Intercreditor Agreement—Bankruptcy; DIP Financing; Adequate Protection."

"Collateral" means all assets and properties subject to, or purported to be subject to, Liens created pursuant to any Second Lien Collateral Document to secure one or more Series of Second Lien Obligations and shall include any property or assets subject to replacement Liens or adequate protection Liens in favor of any Second Lien Claimholder.

"Common Collateral Documents" has the meaning set forth in the Senior Lien Intercreditor Agreement.

"Controlling Claimholders" means Series of Second Lien Claimholders whose Second Lien Representative is the Designated Representative.

"Deposit Accounts" has the meaning given to such in the UCC.

"Designated Representative" (i) until the Non-Controlling Representative Enforcement Date, the Major Controlling Representative and (ii) from and after the Non-Controlling Representative Enforcement Date, the Major Non-Controlling Representative.

"Designation" means a designation of Additional Second Lien Debt, in substantially the form of *Exhibit B* to the Second Lien Pari Passu Intercreditor Agreement.

"Discharge" means, with respect to any Series of Second Lien Obligations, that such Series of Second Lien Obligations is no longer secured by, and no longer required to be secured by, any Shared Collateral pursuant to the terms of the applicable Second Lien Documents for such Series of Second Lien Obligations. The term "*Discharged*" shall have a corresponding meaning.

"Equity Release Proceeds" has the meaning set forth under the caption "—Second Lien Pari Passu Intercreditor Agreement—Automatic Release of Liens."

"Event of Default" means an "Event of Default" (or similarly defined term) as defined in any Second Lien Document.

"Initial Other Second Lien Claimholders" means the holders of any Initial Other Second Obligations, the Initial Other Second Lien Representative and the Initial Other Second Lien Collateral Agent.

"Initial Other Indenture" means an Other Second Lien Agreement pursuant to which the Issuer or the Guarantors incur the Initial Other Second Lien Obligations.

"Initial Other Second Lien Collateral Agent" means the collateral agent for the Initial Other Second Lien Claimholders (in such capacity and together with its successors from time to time in such capacity).

"Initial Other Second Lien Collateral Document" means the Security Documents (as defined in the Initial Other Indenture) and any other agreement, document or instrument entered into for the purpose of granting a Lien to secure any Initial Other Second Lien Obligations or to perfect such Lien (as each may be amended, restated, amended and restated, supplemented or otherwise modified from time to time).

"Initial Other Second Lien Documents" means the Initial Other Indenture, each Initial Other Second Lien Collateral Document and each of the other agreements, documents and instruments providing for or evidencing any other Initial Other Second Lien Obligations, as each may be amended, restated, amended and restated, supplemented or otherwise modified from time to time

"Initial Other Second Lien Obligations" means the Other Second Lien Obligations pursuant to the Initial Other Second Lien Documents.

"Initial Other Second Lien Representative" means the trustee for the Initial Other Second Lien Claimholders (in such capacity and together with its successors from time to time in such capacity).

"Major Controlling Representative" means the Second Lien Representative of the Series of Second Lien Obligations that constitutes the largest outstanding principal amount of any then outstanding Series of Second Lien Obligations; provided, however, that if there are two outstanding Series of Second Lien Obligations which have an equal outstanding principal amount, the Series of Second Lien Obligations with the earlier maturity date shall be considered to have the larger outstanding principal amount for purposes of this definition. For purposes of this definition, "principal amount" shall be deemed to include the face amount of any outstanding letter of credit issued under the particular Series.

"Major Non-Controlling Representative" means the Second Lien Representative (other than the Major Controlling Representative) of the Series of Second Lien Obligations that constitutes the largest outstanding principal amount of any then outstanding Series of Second Lien Obligations; provided, however, that if there are two such outstanding Series of Second Lien Obligations which have an equal outstanding principal amount, the Series of Second Lien Obligations with the earlier maturity date shall be considered to have the larger outstanding principal amount for purposes of this definition. For purposes of this definition, "principal amount" shall be deemed to include the face amount of any outstanding letter of credit issued under the particular Series.

"Non-Controlling Claimholder" means the Second Lien Claimholders which are not Controlling Claimholders.

"Non-Controlling Representative" means, at any time, each Second Lien Representative that is not the Designated Representative at such time.

"Non-Controlling Representative Enforcement Date" means, with respect to any Non-Controlling Representative, the date which is 180 days (throughout which 180 day period such Non-Controlling Representative was the Major Non-Controlling Representative) after the occurrence of both (i) an Event of Default (under and as defined in the Second Lien Documents under which such Non-Controlling Representative is the Second Lien Representative) and (ii) each Second Lien Collateral Agents' and each other Second Lien Representative's receipt of written notice from such Non-Controlling Representative certifying that (x) such Non-Controlling Representative is the Major Non-Controlling Representative and that an Event of Default (under and as defined in the Second Lien Documents under which such Non-Controlling Representative is the Second Lien Representative) has occurred and is continuing and (y) the Second Lien Obligations of the Series with respect to which such Non-Controlling Representative is the Second Lien Representative are currently due and payable in full (whether as a result of acceleration thereof or otherwise) in accordance with the terms of the applicable Other Second Lien Document; provided that the Non-Controlling Representative Enforcement Date shall be stayed and shall not occur and shall be deemed not to have occurred (1) at any time the Applicable Collateral Agent acting on the instructions of the Designated Representative has commenced and is diligently pursuing any enforcement action with respect to Shared Collateral, (2) at any time that a Debtor that has granted a security interest in Shared Collateral is then a debtor under or with respect to (or otherwise subject to) any Insolvency or Liquidation Proceeding or (3) if such Non-Controlling Representative subsequently rescinds or withdraws the written notice provided for in clause (ii).

"Other Second Lien Agreement" means any indenture, notes, credit agreement or other agreement, document (including any document governing reimbursement obligations in respect of letters of credit issued pursuant to any Other Second Lien Agreement) or instrument, pursuant to which any Debtor has or will incur Other Second Lien Obligations; provided that, in each case, the Indebtedness thereunder (other than the Other Second Lien Obligations) has been designated as Other Second Lien Obligations pursuant to and in accordance the terms of the Second Lien Pari Passu Intercreditor Agreement. For avoidance of doubt, the 2024 Indenture shall not constitute an Other Second Lien Agreement.

"Other Second Lien Claimholders" means the holders of any Other Second Lien Obligations and any Second Lien Representative and the Second Lien Collateral Agent with respect thereto and shall include the Initial Other Second Lien Claimholders.

"Other Second Lien Collateral Documents" means the security documents and any other agreement, document or instrument entered into for the purpose of granting a Lien to secure any Other Second Lien Obligations or to perfect such Lien (as each may be amended, restated, amended and restated, supplemented or otherwise modified from time to time).

"Other Second Lien Documents" means, with respect to the Initial Other Second Lien Obligations or any Series of Other Second Lien Obligations, the Other Second Lien Agreements, including the Initial Other Second Lien Documents, and the Other Second Lien Collateral Documents applicable thereto and each other agreement, document and instrument providing for or evidencing any other Other Second Lien Obligation, as each may be amended, restated, amended and restated, supplemented or otherwise modified from time to time; provided that, in each case, the Indebtedness thereunder (other than the Initial Other Second Lien Obligations) has been designated as Other Second Lien Obligations pursuant to and in accordance with the Second Lien Pari Passu Intercreditor Agreement.

"Other Second Lien Obligations" means all amounts owing to any Other Second Lien Claimholder (including any Initial Other Second Lien Claimholder) pursuant to the terms of any Other Second Lien Document (including the Initial Other Second Lien Documents), including all amounts in respect of any principal, interest (including any Post-Petition Interest), premium (if any), penalties, fees, expenses (including fees, expenses and disbursements of agents, professional advisors and legal counsel), indemnifications, reimbursements, damages and other liabilities, and guarantees of the foregoing amounts, in each case whether or not allowed or allowable in an Insolvency or Liquidation Proceeding. Other Second Lien Obligations shall include any Registered Equivalent Notes and guarantees thereof by the Debtors issued in exchange therefor. For avoidance of doubt, the 2024 Indenture Obligations shall not constitute Other Second Lien Obligations.

"Possessory Collateral" means any Shared Collateral in the possession of any Second Lien Collateral Agent (or its agents or bailees), to the extent that possession thereof perfects a Lien thereon under the Uniform Commercial Code of any jurisdiction or otherwise. Possessory Collateral includes any Certificated Securities, Promissory Notes, Instruments, and Tangible Chattel Paper, in each case, delivered to or in the possession of any Second Lien Collateral Agent under the terms of the Second Lien Collateral Documents.

"Post-Petition Interest" means interest, fees, expenses and other charges that pursuant to the 2024 Indenture Documents or Other Second Lien Documents, as applicable, continue to accrue after the commencement of any Insolvency or Liquidation Proceeding, whether or not such interest, fees, expenses and other charges are allowed or allowable under the Bankruptcy Law or in any such Insolvency or Liquidation Proceeding.

"Proceeds" means all proceeds of any sale, collection or other liquidation of any Collateral comprising either Shared Collateral or Equity Release Proceeds and all proceeds of any such distribution and any proceeds of any insurance covering the Shared Collateral received by the Applicable Collateral Agent and not returned to any Debtor under any Second Lien Document.

"Refinance" means, in respect of any Indebtedness, to refinance, extend, renew, defease, amend, modify, supplement, restructure, replace, refund or repay, or to issue other Indebtedness in exchange or replacement for, such Indebtedness in whole or in part and regardless of whether the principal amount of such Refinancing Indebtedness is the same, greater than or less than the principal amount of the Refinanced Indebtedness. "Refinanced" and "Refinancing" shall have correlative meanings.

"Registered Equivalent Notes" means, with respect to any notes originally issued in a Rule 144A or other private placement transaction under the Securities Act of 1933, substantially identical notes (having the same guarantees and substantially the same collateral) issued in a dollar-for-dollar exchange therefor pursuant to an exchange offer registered with the SEC.

"Second Lien Claimholders" means (i) the 2024 Indenture Claimholders and (ii) the Other Second Lien Claimholders with respect to each Series of Other Second Lien Obligations.

"Second Lien Collateral Agent" means (i) each Common Security Agent and (ii)(x) in the case of any 2024 Indenture Obligations, the 2024 Second Lien Collateral Agent and (y) in the case of the Other Second Lien Obligations, the Other Second Lien Collateral Agent (which in the case of the Initial Other Second Lien Obligations shall be the Initial Other Second Lien Collateral Agent and in the case of any other Series of Other Second Lien Obligations shall be the Additional Second Lien Collateral Agent for such Series).

"Second Lien Collateral Documents" means (i) the Common Collateral Documents, (ii) Other Second Lien Collateral Documents and (iii) each of the collateral agreements, security agreements and other instruments and documents executed and delivered by any Corporate Debtor or any other Debtor creating or purporting to create any Lien on any Collateral to secure any Second Lien Obligations.

"Second Lien Documents" means (i) the 2024 Indenture Documents, (ii) the Initial Other Second Lien Documents and (iii) each other Other Second Lien Documents.

"Second Lien Obligations" means, collectively, (i) the 2024 Indenture Obligations and (ii) each Series of Other Second Lien Obligations.

"Second Lien Representatives" means, at any time, (i) in the case of any 2024 Indenture Obligations or the 2024 Second Lien Claimholders, the Trustee, (ii) in the case of the Initial Other Second Lien Obligations or the Initial Other Second Lien Claimholders, the Initial Other Second Lien Representative, and (iii) in the case of any other Series of Other Second Lien Obligations or Other Second Lien Claimholders of such Series that becomes subject to the Second Lien Pari Passu Intercreditor after the date thereof, the Additional Second Lien Representative for such Series.

"Series" means (a) with respect to the Second Lien Claimholders, each of (i) the 2024 Indenture Claimholders (in their capacities as such), (ii) the Initial Other Second Lien Claimholders (in their capacities as such), and (iii) the Other Second Lien Claimholders (in their capacities as such) that become subject to this Agreement after the date hereof that are represented by a common Second Lien Representative (in its capacity as such for such Other Second Lien Claimholders) and (b) with respect to any Second Lien Obligations, each of (i) the 2024 Indenture Obligations, (ii) the Initial Other Second Lien Obligations, and (iii) the Other Second Lien Obligations incurred pursuant to any Other Second Lien Document, which pursuant to any Joinder Agreement, are to be represented hereunder by a common Second Lien Representative (in its capacity as such for such Other Second Lien Obligations).

"Shared Collateral" means, at any time, Collateral in which the holders of two or more Series of Second Lien Obligations (or their respective Second Lien Representatives or Second Lien Collateral Agents on behalf of such holders) hold, or purport to hold, or are required to hold pursuant to the Second Lien Documents in respect of such Series, a valid security interest or Lien at such time. If more than two Series of Second Lien Obligations are outstanding at any time and the holders of less than all Series of Second Lien Obligations hold, or purport to hold, or are required to hold pursuant to the Second Lien Documents in respect of such Series, a valid security interest or Lien in any Collateral at such time, then such Collateral shall constitute Shared Collateral for those Series of Second Lien Obligations that hold, or purport to hold, or are required to hold pursuant to the Second Lien Documents in respect of such Series, a valid security interest or Lien in such Collateral at such time and shall not constitute Shared Collateral for any Series which does not hold, or purport to hold, or are required to hold pursuant to the Second Lien Documents in respect of such Series, a valid security interest or Lien in such Collateral at such time.

"Underlying Assets" has the meaning set forth under the caption "—Second Lien Pari Passu Intercreditor Agreement—Automatic Release of Liens."

Application of proceeds

The Second Lien Pari Passu Intercreditor Agreement will provide that, anything contained therein or in any of the Second Lien Documents to the contrary notwithstanding, if an Event of Default has occurred and is continuing, and the Applicable Collateral Agent is taking action to enforce rights in respect of any Collateral, or any distribution is made in respect of any Shared Collateral in any Bankruptcy Case of any Debtor or any Second Lien Representative or Second Lien Claimholder receives any payment pursuant to the Senior Lien Intercreditor Agreement, the Security Agency and Subordination Agreement or any other intercreditor agreement (other than the Second Lien Pari Passu Intercreditor Agreement) or otherwise with respect to any Shared Collateral, the Proceeds shall be applied by the Applicable Collateral Agent or a Second Lien Representative in the following order:

(i) FIRST, to the payment of all amounts owing to each Common Security Agent (in its capacity as such), any Receiver or any Delegate, including all reasonable costs and expenses incurred by each Common Security Agent or any such Receiver or Delegate (in each case in its capacity as such) in connection with such collection or sale or otherwise in connection with this Agreement, any other Second Lien Document or any of the Second Lien Obligations, including all court costs and the reasonable fees and expenses of its agents and legal counsel, and any other reasonable costs or expenses incurred in connection with the exercise of any right or remedy hereunder or under any other Second Lien Document and all fees and indemnities owing to such Common Security Agents or such Receiver or Delegate, ratably to each such Common Security Agent, Receiver or Delegate in accordance with the amounts payable to it pursuant to this clause (i);

(ii) SECOND, to the payment of all amounts owing to the Intercreditor Agent (in its capacity as such), including all reasonable costs and expenses incurred by the Intercreditor Agent (in its capacity as such) in connection with this Agreement, any other Second Lien Document or any of the Second Lien Obligations, including all court costs and the reasonable fees and expenses of its agents and legal counsel, and any other reasonable costs or expenses incurred in connection with the exercise of any right or remedy hereunder or under any other Second Lien Document and all fees and indemnities owing to the Intercreditor Agent;

(iii) THIRD, to the payment of all amounts owing to each Second Lien Collateral Agent (other than the Common Security Agents) and each Second Lien Representative (in its capacity as such) secured by such Shared Collateral or, in the case of Equity Release Proceeds, secured by the Underlying Assets, including all reasonable costs and expenses incurred by each Second Lien Collateral Agent (in its capacity as such) and each Second Lien Representative (in its capacity as such) in connection with such collection or sale or otherwise in connection with the Second Lien Pari Passu Intercreditor Agreement, any other Second Lien Document or any of the Second Lien Obligations, including all court costs and the reasonable fees and expenses of its agents and legal counsel, and any other reasonable costs or expenses incurred in connection with the exercise of any right or remedy hereunder or under any other Second Lien Document and all fees and indemnities owing to such Second Lien Collateral Agents and Second Lien Representatives, ratably to each such Second Lien Collateral Agent and Second Lien Representative in accordance with the amounts payable to it pursuant to this clause (iii);

(iv) FOURTH, subject to the terms of the next full paragraph below and terms relating to similar liens contained in the Second Lien Pari Passu Intercreditor Agreement, to the extent Proceeds remain after the application pursuant to the preceding *clauses (i) to (iii)*, to each Second Lien Representative for the payment in full of the other Second Lien Obligations of each Series secured by such Shared Collateral or, in the case of Equity Release Proceeds, secured by the Underlying Assets, and, if the amount of such Proceeds are insufficient to pay in full the Second Lien Obligations of each Series so secured then such Proceeds shall be allocated among the Second Lien Representatives of each Series secured by such Shared Collateral or, in the case of Equity Release Proceeds, secured by the Underlying Assets, *pro rata* according to the amounts of such Second Lien Obligations owing to each such respective Second Lien Representative and the other Second Lien Claimholders represented by it for distribution by such Second Lien Representative in accordance with its respective Second Lien Documents; and

(v) FIFTH, any balance of such Proceeds remaining after the application pursuant to preceding *clauses (i)* to *(iv)*, to the Debtors, their successors or assigns from time to time, or to whomever may be lawfully entitled to receive the same.

Actions with respect to Shared Collateral; prohibition on contesting liens

The Second Lien Pari Passu Intercreditor Agreement will provide that, notwithstanding the terms set forth under the caption "—Application of Proceeds", (i) only the Applicable Collateral Agent shall act or refrain from acting with respect to Shared Collateral (including with respect to any other intercreditor agreement with respect to any Shared Collateral), (ii) the Applicable Collateral Agent shall act only on the instructions of the Designated Representative and shall not follow any instructions with respect to such Shared Collateral (including with respect to any other intercreditor agreement with respect to any Shared Collateral) from any Non-Controlling Representative (or any other Second Lien Claimholder other than the Designated Representative) and (iii) no other Second Lien Claimholder shall or shall instruct any Second Lien Collateral Agent to, and any other Second Lien Collateral Agent that is not the Applicable Collateral Agent shall not, commence any judicial or nonjudicial foreclosure proceedings with respect to, seek to have a trustee, receiver, liquidator or similar official appointed for or over, attempt any action to take possession of, exercise any right, remedy or power with respect to, or otherwise take any action to enforce its security interest in or realize upon, or take any other action available to it in respect of, Shared Collateral (including with respect to any other intercreditor agreement with respect to Shared Collateral), whether under any Second Lien Collateral Document (other than the Second Lien Collateral Documents applicable to the Applicable Collateral Agent), applicable law or otherwise, it being agreed that only the Applicable Collateral Agent, acting in accordance with the Second Lien Collateral Documents applicable to it, shall be entitled to take any such actions or exercise any remedies with respect to such Shared Collateral at such time.

In addition, notwithstanding the equal priority of the Liens securing each Series of Second Lien Obligations granted on the Shared Collateral, the Applicable Collateral Agent (acting on the instructions of the Designated Representative) will be permitted to deal with the Shared Collateral as if such Applicable Collateral Agent had a senior and exclusive Lien on such Shared Collateral. No Non-Controlling Representative, Non-Controlling Claimholder or Second Lien Collateral Agent that is not the Applicable Collateral Agent will be permitted to contest, protest or object to any foreclosure proceeding or action brought by the Applicable Collateral Agent, the Designated Representative or the Controlling Claimholders or any other exercise by the Applicable Collateral Agent, the Designated Representative or the Controlling Claimholders of any rights and remedies relating to the Shared Collateral.

Pursuant to the Second Lien Pari Passu Intercreditor Agreement, each of the Second Lien Collateral Agents (other than the Applicable Collateral Agent) and the Second Lien Representatives (other than the Designated Representative) will agree that it will not accept any Lien on any Collateral for the benefit of any Series of Other Second Lien Obligations (other than funds deposited for the satisfaction, discharge or defeasance of any Other Second Lien Agreement) other than pursuant to the Second Lien Collateral Documents, and by executing Second Lien Pari Passu Intercreditor Agreement, each such Second Lien Collateral Agent and each such Second Lien Representative and the Series of Second Lien Claimholders for which it is acting pursuant to the Second Lien Pari Passu Intercreditor Agreement will agree to be bound by the provisions of the Second Lien Pari Passu Intercreditor Agreement and the other Second Lien Collateral Documents applicable to it.

In addition, each of the Second Lien Claimholders will agree that it will not (and will waive any right to) contest or support any other Person in contesting, in any proceeding (including any Insolvency or Liquidation Proceeding), the perfection, priority, validity or enforceability of a Lien held by or on behalf of any of the Second Lien Claimholders in all or any part of the Collateral or the provisions of the Second Lien Pari Passu Intercreditor Agreement; provided that nothing in the Second Lien Pari Passu Intercreditor Agreement shall be construed to prevent or impair (i) the rights of any Second Lien Collateral Agent or any Second Lien Representative to enforce the Second Lien Pari Passu Intercreditor Agreement or (ii) the rights of any Second Lien Secured Party to contest or support any other Person in contesting the enforceability of any Lien purporting to secure obligations not constituting Second Lien Obligations.

Automatic release of liens

If, at any time any Shared Collateral is transferred to a third party or otherwise disposed of, in each case, in connection with any enforcement by the Applicable Collateral Agent in accordance with the provisions of the Second Lien Pari Passu Intercreditor Agreement, then (whether or not any Insolvency or Liquidation Proceeding is pending at the time) the Liens in favor of the other Second Lien Collateral Agents for the benefit of each Series of Second Lien Claimholders (or in favor of such other Second Lien Claimholders if directly secured by such Liens) upon such Shared Collateral will automatically be released and discharged upon final conclusion of such disposition as and when, but only to the extent, such Liens of the Applicable Collateral Agent on such Shared Collateral are released and discharged; provided that any proceeds of any Shared Collateral realized therefrom shall be applied pursuant to the priority set forth in the Second Lien Pari Passu Intercreditor Agreement. If in connection with any such foreclosure or other exercise of remedies by the Applicable Collateral Agent, the Applicable Collateral Agent or related Designated Representative of such Series of Second Lien Obligations releases any guarantor from its obligation under a guarantee of the Series of Second Lien Obligations for which it serves as agent prior to a Discharge of such Series of Second Lien Obligations, such guarantor also shall be automatically released from its guarantee of all other Second Lien Obligations. If in connection with any such foreclosure or other exercise of remedies by the Applicable Collateral Agent, the equity interests of any Person are foreclosed upon or otherwise disposed of and the Applicable Collateral Agent releases its Lien on the property or assets of such Person, then the Liens of each other Second Lien Collateral Agent (or in favor of such other Second Lien Claimholders if directly secured by such Liens) with respect to any Collateral consisting of the property or assets of such Person will be automatically released to the same extent as the Liens of the Applicable Collateral Agent are released; provided that any proceeds of any such equity interests foreclosed upon where the Applicable Collateral Agent releases its Lien on the assets of such Person on which another Series of Second Lien Obligations holds a Lien on any of the assets of such Person (any such assets, the "Underlying Assets") which Lien is released as provided in this sentence (any such Proceeds being referred to herein as "Equity Release Proceeds" regardless of whether or not such other Series of Second Lien Obligations holds a Lien on such equity interests so disposed of) shall be applied pursuant to the priority set forth in the Second Lien Pari Passu Intercreditor Agreement.

Waiver of right of marshaling

Pursuant to the Second Lien Pari Passu Intercreditor Agreement, each Non-Controlling Claimholder will agree that none of the Applicable Collateral Agent, the Designated Representative or any other Second Lien Claimholder shall have any duty or obligation first to marshal or realize upon any type of Shared Collateral (or any other Collateral securing any of the Second Lien Obligations), or to sell, dispose of or otherwise liquidate all or any portion of such Shared Collateral (or any other Collateral securing any Second Lien Obligations), in any manner that would maximize the return to the Non-Controlling Claimholders, notwithstanding that the order and timing of any such realization, sale, disposition or liquidation may affect the amount of proceeds actually received by the Non-Controlling Claimholders from such realization, sale, disposition or liquidation.

Bankruptcy; DIP financing; adequate protection

The Second Lien Pari Passu Intercreditor Agreement will provide that if any Debtor shall become subject to a case (a "Bankruptcy Case") under the Bankruptcy Code and shall, as debtor(s)-in-possession, move for approval of financing ("DIP Financing") to be provided by one or more lenders (the "DIP Lenders") under Section 364 of the Bankruptcy Code or the use of cash collateral under Section 363 of the Bankruptcy Code, each Second Lien Claimholder (other than any Controlling Claimholder or any Second Lien Representative of any Controlling Claimholder) will agree that it will not raise any objection to any such financing or to the Liens on the Shared Collateral securing the same ("DIP Financing Liens") or to any use of cash collateral that constitutes Shared Collateral, unless a Second Lien Representative of the Controlling Claimholders shall then oppose or object to such DIP Financing or such DIP Financing Liens or use of cash collateral (and (i) to the extent that such DIP Financing Liens are senior to the Liens on any such Shared Collateral for the benefit of the Controlling Claimholders, each Non-Controlling Claimholder will subordinate its Liens with respect to such Shared Collateral on the same terms as the Liens of the Controlling Claimholders (other than any Liens of any Second Lien Claimholders constituting DIP Financing Liens) are subordinated thereto, and (ii) to the extent that such DIP Financing Liens rank *pari passu* with the Liens on any such Shared Collateral granted to secure the Second Lien Obligations of the Controlling Claimholders, each Non-Controlling Claimholder will confirm the priorities with respect to such Shared Collateral as set forth in the Second Lien Pari Passu Intercreditor Agreement), in each case so long as (A) the Second Lien Claimholders of each Series retain the benefit of their Liens on all such Shared Collateral pledged to the DIP Lenders, including proceeds thereof arising after the commencement of such proceeding, with the same priority vis-à-vis all the other Second Lien Claimholders (other than any Liens of the Second Lien Claimholders constituting DIP Financing Liens) as existed prior to the commencement of the Bankruptcy Case, (B) the Second Lien Claimholders of each Series are granted Liens on any additional collateral pledged to any Second Lien Claimholders as adequate protection or otherwise in connection with such DIP Financing or use of cash collateral, with the same priority vis-à-vis the Second Lien Claimholders as set forth in the Second Lien Pari Passu Intercreditor Agreement (other than any Liens of any Second Lien Claimholders constituting DIP Financing Liens), (C) if any amount of such DIP Financing or cash collateral is applied to repay any of the Second Lien Obligations, such amount is applied pursuant to the terms of the Second Lien Pari Passu Intercreditor Agreement, and (D) if any Second Lien Claimholders are granted adequate protection with respect to the Second Lien Obligations subject hereto, including in the form of periodic payments, in connection with such use of cash collateral, the proceeds of such adequate protection are applied pursuant to the terms of the Second Lien Pari Passu Intercreditor Agreement; provided that the Second Lien Claimholders of each Series shall have a right to object to the grant of a Lien to secure the DIP Financing over any Collateral subject to Liens in favor of the Second Lien Claimholders of such Series or its Second Lien Representative that shall not constitute Shared Collateral (unless such Collateral fails to constitute Shared Collateral because the Lien in respect thereof constitutes a Declined Lien with respect to such Second Lien Claimholders or their Second Lien Representative or the Applicable Collateral Agent); provided, further, that the Second Lien Claimholders receiving adequate protection shall not be permitted to object to any other Second Lien Claimholder receiving adequate protection comparable to any adequate protection granted to such Second Lien Claimholders in connection with a DIP Financing or use of cash collateral.

The Second Lien Pari Passu Intercreditor Agreement will provide that, if any Second Lien Claimholder is granted adequate protection (A) in the form of Liens on any additional collateral, then each other Second Lien Claimholder shall be entitled to seek, and each Second Lien Claimholder will consent and not object to, adequate protection in the form of Liens on such additional collateral with the same priority vis-à-vis the Second Lien Claimholders as set forth in the Second Lien Pari Passu Intercreditor Agreement, (B) in the form of a superpriority or other administrative claim, then each other Second Lien Claimholder shall be entitled to seek, and each Second Lien Claimholder will consent and not object to, adequate protection in the form of a pari passu superpriority or administrative claim or (C) in the form of periodic or other cash payments, then the proceeds of such adequate protection must be applied to all Second Lien Obligations pursuant to the terms of the Second Lien Pari Passu Intercreditor Agreement.

Bailee for protection

The Second Lien Pari Passu Intercreditor Agreement will provide that the Applicable Collateral Agent shall be entitled to hold any Possessory Collateral constituting Shared Collateral. Notwithstanding the foregoing, each Second Lien Collateral Agent will agree to hold any Possessory Collateral constituting Shared Collateral and any other Shared Collateral from time to time in its possession or control (or in the possession or control of its agents or bailees) as gratuitous bailee for the benefit of each other Second Lien Claimholder (such bailment being intended, among other things, to satisfy the requirements of Sections 8-106(d)(3), 8-301(a)(2) and 9-313(c) of the UCC) and any assignee, solely for the purpose of perfecting the security interest granted in such Shared Collateral, if any, pursuant to the applicable Second Lien Collateral Documents. Solely with respect to any Deposit Accounts constituting Shared Collateral under the control (within the meaning of Section 9-104 of the UCC) of any Second Lien Collateral Agent, each such Second Lien Collateral Agent will agree to also hold control over such Deposit Accounts as gratuitous agent for each other Second Lien Claimholder and any assignee solely for the purpose of perfecting the security interest in such Deposit Accounts.

Insurance

The Second Lien Pari Passu Intercreditor Agreement will provide that, as among the Second Lien Claimholders, the Applicable Collateral Agent (acting at the direction of the Designated Representative), shall have the right, but not the obligation, to adjust or settle any insurance policy or claim covering or constituting Shared Collateral in the event of any loss thereunder and to approve any award granted in any condemnation or similar proceeding affecting the Shared Collateral. To the extent any Second Lien Collateral Agent or any other Second Lien Claimholder receives proceeds of such insurance policy and such proceeds are not permitted or required to be returned to any Debtor under the applicable Second Lien Documents, such proceeds shall be turned over to the Applicable Collateral Agent for application as provided in accordance with the terms of the Second Lien Pari Passu Intercreditor Agreement.

Amendments, modifications and refinancings

Each Second Lien Collateral Agent will agree pursuant to the terms of the Second Lien Pari Passu Intercreditor Agreement that, without the prior written consent of each other Second Lien Collateral Agent, no Second Lien Collateral Document may be amended, restated, amended and restated, supplemented, replaced or Refinanced or otherwise modified from time to time or entered into to the extent such amendment, supplement, Refinancing or modification, or the terms of any new Second Lien Collateral Document, would be prohibited by, or would require any Debtor to act or refrain from acting in a manner that would violate, any of the terms of the Second Lien Pari Passu Intercreditor Agreement.

The Second Lien Pari Passu Intercreditor Agreement will provide that Second Lien Obligations of any Series may, subject the terms of such agreement, be Refinanced, in whole or in part, in each case, without notice to, or the consent (except to the extent a consent is otherwise required to permit the Refinancing transaction under any Second Lien Document) of any Second Lien Claimholder of any other Series, all without affecting the priorities provided for therein or the other provisions thereof; provided that the Second Lien Representative and Second Lien Collateral Agent of the holders of any such Refinancing Indebtedness shall have executed a joinder agreement to the Second Lien Pari Passu Intercreditor Agreement on behalf of the holders of such Refinancing Indebtedness.

Release of Collateral

The Issuer and the Guarantors are entitled to the releases of property and other assets included in the Collateral from the Liens securing the Notes under any one or more of the following circumstances:

(a) to enable us to consummate the sale, transfer or disposition of such property or assets to another Person (including the Parent Guarantor and its Subsidiaries, but without prejudice to any obligation of any of the Parent Guarantor and its Subsidiaries to provide replacement security) to the extent permitted under the covenant described under "—Certain Covenants—Asset Sales" or not otherwise constituting an Asset Sale;

(b) in respect of the property and assets of a Subsidiary Guarantor, (i) upon the designation of such Subsidiary Guarantor to be an Unrestricted Subsidiary in accordance with the covenant described under "—Certain Covenants—Limitation on Restricted Payments" and the definition of "Unrestricted Subsidiary," and such Subsidiary Guarantor shall be automatically released from its obligations under the indenture and under the Security Documents or (ii) upon the release or discharge of the Subsidiary Guarantee of such Subsidiary Guarantor in accordance with the last paragraph under "—Guarantees" below;

(c) in respect of the property and assets of the Issuer, upon the release or discharge of the Notes Obligations in accordance with the indenture;

(d) as provided in the Senior Lien Intercreditor Documents with respect to enforcement actions by the holders of First Priority Lien Obligations;

(e) as provided in the Second Lien Pari Passu Intercreditor Agreement with respect to enforcement actions by the holders of Second Priority Lien Obligations;

(f) as described under "—Amendments and Waivers" below; and

(g) if the Notes have been discharged or defeased pursuant to a legal defeasance or

(h) covenant defeasance under the indenture as described below under "—Defeasance."

The second priority security interests in all Collateral securing the Notes Obligations also will be released upon (i) payment in full of the principal of, together with accrued and unpaid interest on, the Notes and all other Obligations under the indenture and the Security Documents (other than contingent or unliquidated obligations or liabilities not then due) that are due and payable at or prior to the time such principal, together with accrued and unpaid interest, are paid (including pursuant to a satisfaction and discharge of the indenture as described below under "—Satisfaction and discharge") or (ii) a legal defeasance or covenant defeasance under the indenture as described below under "—Defeasance."

In addition, the Trustee's Liens on the Collateral will be released upon the terms and subject to the conditions set forth in the Security Documents. If the First Priority Lien Obligations are repaid in full and the related commitments terminated thereunder without being replaced, the Liens on the Collateral in favor of the Trustee for the benefit of itself and the holders of the Notes and the Other Second Lien Obligations will not be released at such time, except to the extent the Collateral or any portion thereof was disposed of in order to repay the First Priority Lien Obligations secured by the Collateral in compliance with the provisions described under "—Certain Covenants—Asset Sales."

Guarantees

The Parent Guarantor and each of the Parent Guarantor's Restricted Subsidiaries (other than the Issuer) that are guarantors under the RBL facility, which include KEI, KEI (Brazil Santos), KEI Finance, KPG, New Aus SPV and KUSA Inc. as of the Issue Date, will jointly and severally irrevocably and unconditionally guarantee on a senior basis the performance and punctual payment when due, whether at Stated Maturity, by acceleration or otherwise, of all obligations of the Issuer under the indenture and the Notes, whether for payment of principal of, premium, if any, or interest (or additional interest, if any) and all other monetary obligations of the Issuer under the indenture and the Notes, expenses, indemnification or otherwise (all such obligations guaranteed by such Guarantors with respect to the Notes being herein called the "Guaranteed Obligations"). The Guaranteed Obligations of all Guarantors shall be secured by security interests (subject to Permitted Liens) in the Collateral owned by such Guarantor pursuant to the terms of the Security Documents (but subject to the terms and conditions of the Security Documents and the Senior Lien Intercreditor Documents and any applicable Customary Intercreditor Agreement). Such Guarantor will agree to pay, in addition to the amount stated above, any and all expenses (including reasonable counsel fees and expenses) incurred by the Trustee or the holders in enforcing any rights under the Guarantees.

Each Subsidiary Guarantee will be limited to an amount not to exceed the maximum amount that can be guaranteed by the applicable Subsidiary Guarantor without rendering the Subsidiary Guarantee, as it relates to such Subsidiary Guarantor, voidable under applicable law relating to fraudulent conveyance or fraudulent transfer or similar laws affecting the rights of creditors generally or capital maintenance or corporate benefit rules applicable to guarantees for obligations of affiliates. See "Risk Factors—Risks Related to the Notes and Security—Each Guarantor's liability under its Guarantee may be reduced to zero, avoided or released under certain circumstances, in which case you may not receive any payments from some or all of the Guarantors."

Each Guarantee will be a continuing guarantee and shall:

(a) remain in full force and effect until payment in full of all the Guaranteed Obligations;

(b) subject to the next succeeding paragraph, be binding upon each such Guarantor and its successors; and

(c) inure to the benefit of and be enforceable by the Trustee, the holders and their successors, transferees and assigns.

A Subsidiary's Subsidiary Guarantee will be automatically released upon any of the following:

(1) the sale, disposition, exchange or other transfer (including through merger, consolidation, amalgamation or otherwise) of the Capital Stock (including any sale, disposition or other transfer following which the applicable Subsidiary Guarantor is no longer a Restricted Subsidiary), of the applicable Subsidiary Guarantor if such sale, disposition, exchange or other transfer is made to a person that is not (either before or after giving effect to such transaction) the Parent Guarantor or a Restricted Subsidiary of the Parent Guarantor in a transaction that is permitted by the indenture and the Subsidiary Guarantor ceases to be a Subsidiary of the Parent Guarantor as a result of such sale or disposition;

(2) the designation of such Subsidiary Guarantor as an Unrestricted Subsidiary in accordance with the covenant described under "—Certain Covenants—Limitation on Restricted Payments" and the definition of "Unrestricted Subsidiary";

(3) the Issuer's exercise of its legal defeasance option or covenant defeasance option as described under "—Defeasance" or if the Issuer's obligations under the indenture are discharged in accordance with the terms of the indenture;

(4) such Subsidiary Guarantor ceasing to be a Subsidiary as a result of any foreclosure of any pledge or security interest in favor of First Priority Lien Obligations or other exercise of remedies in respect thereof, subject to, in each case, the application of the proceeds of such foreclosure or exercise of remedies in the manner described in the Senior Lien Intercreditor Agreement and any applicable Customary Intercreditor Agreement; or

(5) as provided under "—Amendments and Waivers."

Future Guarantors

The indenture will provide that the Parent Guarantor will cause each Wholly Owned Restricted Subsidiary that (1) Incurs or guarantees any Indebtedness under the RBL facility; or (2) Incurs or guarantees any Credit Facility or other Indebtedness excess of US$25.0 million (except where (a) such Incurrence referred to in (1) or (2) is by virtue of solely being a party to an Australian Securities and Investments Commission deed of cross guarantee under Part 2M.6 of the Australian Corporations Act 2001 (Cth), (b) would require granting a guarantee that would result in a breach or violation of statutory limits, corporate benefit, financial assistance, fraudulent preference, thin capitalization rules, capital maintenance rules, guidance and coordination rules or the laws, rules or regulations (or analogous restrictions) of any applicable jurisdiction or (c) would require granting a guarantee that would reasonably be expected to give rise to personal liability for officers or directors of such Restricted Subsidiary), to execute and deliver to the Trustee a supplemental indenture pursuant to which such Subsidiary will guarantee the Issuer's Obligations under the Notes and the indenture on the terms and conditions set forth in the indenture, a joinder to the Security Documents, and, to the extent required pursuant to the covenant described under "—Security—After-Acquired Property," a joinder agreement to each applicable Security Document or new Security Documents and take all action required thereunder to perfect the Liens created thereunder, if required by the Senior Lien Intercreditor Documents, a joinder to the Senior Lien Intercreditor Documents and if required by any Customary Intercreditor Agreement, a joinder to such Customary Intercreditor Agreement, in each case within 60 days of the date on which it guaranteed such Indebtedness.

Each Guarantee will be limited to an amount not to exceed the maximum amount that can be guaranteed by the relevant Guarantor without rendering the Guarantee or the indenture, as it relates to such Guarantor, voidable under applicable law relating to fraudulent conveyance or fraudulent transfer or similar laws affecting the rights of creditors generally or capital maintenance or corporate benefit rules applicable to guarantees for obligations of affiliates.

Each Subsidiary Guarantee shall be released in accordance with the provisions of the indenture described under "—Guarantees."

Change of Control

Upon the occurrence of a Change of Control, each holder of Notes will have the right to require the Issuer to repurchase all or any part of such holder's Notes at a purchase price in cash equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to, but excluding, the date of repurchase (the "Change of Control Payment Date") (subject to the right of the holders of record on the relevant record date to receive interest due on the relevant interest payment date), except to the extent the Issuer has previously or concurrently elected to redeem such Notes as described under "—Optional Redemption."

In the event that at the time of such Change of Control, the terms of the RBL facility or any other Bank Indebtedness restrict or prohibit the repurchase of such Notes pursuant to this covenant, then prior to the delivery of the notice to holders provided for in the immediately following paragraph but in any event within 30 days following any Change of Control, the Issuer or the Parent Guarantor, as applicable, shall:

(a) repay in full all Bank Indebtedness or, if doing so will allow the purchase of such Notes, offer to repay in full all Bank Indebtedness and repay the Bank Indebtedness of each lender and/or noteholder who has accepted such offer; or

(b) obtain the requisite consent under the agreements governing the Bank Indebtedness to permit the repurchase of such Notes as provided for in the immediately following paragraph.

See "Risk Factors—Risks Related to the Notes and Security—We may not be able to repurchase the Notes upon a change of control, which would cause a default under the Indenture."

Within 30 days following any Change of Control, except to the extent that the Issuer has exercised its right to redeem such Notes by delivery of a notice of redemption as described under "—Optional Redemption," the Issuer shall mail (or otherwise deliver in accordance with the applicable procedures of DTC) a notice (a "Change of Control Offer") to each holder of such Notes with a copy to the Trustee stating:

(1) that a Change of Control has occurred and that such holder has the right to require the Issuer to repurchase such holder's Notes at a repurchase price in cash equal to 101% of the principal amount thereof, plus accrued and unpaid interest and additional interest, if any, to the date of repurchase (subject to the right of holders of record on a record date to receive interest on the relevant interest payment date);

(2) the circumstances and relevant facts and financial information regarding such Change of Control;

(3) the repurchase date (which shall be no earlier than 10 days nor later than 30 days from the date such notice is sent);

(4) that unless the Issuer defaults in making the payment, all Notes accepted for repurchase pursuant to the Change of Control Offer will cease to accrue interest on the Change of Control Offer Payment Date;

(5) that holders of such Notes electing to have any such Notes repurchased pursuant to a Change of Control Offer will be required to notify the Trustee prior to the close of business on the third Business Day preceding the Change of Control Offer Payment Date; and

(6) the other instructions determined by the Issuer or as reasonably requested by the Trustee, consistent with this covenant, that a holder of such series must follow in order to have its Notes of such series purchased.

A Change of Control Offer may be made in advance of a Change of Control, and conditioned upon such Change of Control, if a definitive agreement is in place for the Change of Control at the time of making of the Change of Control Offer.

Notwithstanding the foregoing provisions of this "Change of Control," the Issuer will not be required to make a Change of Control Offer upon a Change of Control if (1) a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the indenture applicable to a Change of Control Offer made by the Issuer and purchases all Notes validly tendered and not withdrawn under such Change of Control Offer or (2) to the extent the Issuer has previously or concurrently elected to redeem such Notes and has given notice of redemption as described under "—Optional Redemption" unless and until there is a default in payment of the applicable redemption price.

Promptly following the expiration of the Change of Control Offer, the Issuer will, to the extent lawful, accept for payment all Notes or portions thereof properly tendered pursuant to the Change of Control Offer, and the Issuer will:

(i) on the Change of Control Payment Date, deposit with the paying agent an amount equal to the payment in connection with the repurchase of all Notes or portions thereof properly tendered; and

(ii) on the Change of Control Payment Date, deliver or cause to be delivered to the Trustee the Notes properly accepted together with an Officers' Certificate stating the aggregate principal amount of Notes or portion thereof being purchased by the Issuer.

Notes repurchased by the Issuer pursuant to a Change of Control Offer will have the status of Notes issued but not outstanding or will be retired and canceled at the option of the Issuer. Notes purchased by a third party pursuant to the preceding paragraphs will have the status of Notes issued and outstanding.

The Issuer will comply, to the extent applicable, with the requirements of Section 14(e) of the Exchange Act and any other securities laws or regulations in connection with the repurchase of Notes as a result of a Change of Control. To the extent that the provisions of any securities laws or regulations conflict with these Change of Control provisions, the Issuer will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations under this covenant by virtue thereof.

The Issuer has no present intention to engage in a transaction involving a Change of Control, although it is possible that the Issuer could decide to do so in the future. Subject to the limitations discussed below, the Issuer could, in the future, enter into certain transactions, including acquisitions, refinancings or other recapitalizations, that would not constitute a Change of Control under the indenture, but that could increase the amount of indebtedness outstanding at such time or otherwise affect the Issuer's capital structure or credit rating.

The occurrence of events that would constitute a Change of Control would constitute a review event under the RBL facility that may permit the lenders to accelerate the maturity of borrowings and terminate their commitments to lend. See "Description of Other Financing Arrangements—Reserve Based Lending Facility—Mandatory Prepayment and Review Events." Future Bank Indebtedness of the Issuer may contain prohibitions on certain events that would constitute a Change of Control or require such Bank Indebtedness to be repurchased upon a Change of Control. Moreover, the exercise by the holders of their right to require the Issuer to repurchase the Notes could cause a default under such Bank Indebtedness, even if the Change of Control itself does not, due to the financial effect of such repurchase on the Issuer and the Parent Guarantor. Finally, the Issuer's ability to pay cash to the holders upon a repurchase may be limited by the Issuer's then existing financial resources. There can be no assurance that sufficient funds will be available when necessary to make any required repurchases. See "Risk Factors—Risks Related to Our Indebtedness and the Notes—We may not be able to repurchase the Notes upon a change of control."

The definition of Change of Control includes a phrase relating to the sale, lease or transfer of "all or substantially all" the properties and assets of the Parent Guarantor and its Subsidiaries taken as a whole. Although there is a developing body of case law interpreting the phrase "substantially all," under New York law, which governs the indenture, there is no precise established definition of the phrase. Accordingly, the ability of a holder of Notes to require the Issuer to repurchase such Notes as a result of a sale, lease, transfer or other disposition of less than all of the assets of the Parent Guarantor and its Subsidiaries taken as a whole to another Person or group may be uncertain.

The provisions under the indenture relating to the Issuer's obligation to make an offer to repurchase the Notes as a result of a Change of Control with respect to the Notes may be waived or modified with the written consent of the holders of a majority in principal amount of such Notes.

Certain Covenants

Set forth below are summaries of certain covenants that will be contained in the indenture. If on any date following the Issue Date, (i) the Notes have Investment Grade Ratings from any two Rating Agencies, and (ii) no Default or Event of Default has occurred and is continuing, then, beginning on that day (the occurrence of the events described in the foregoing clauses (i) and (ii) being collectively referred to as a "Covenant Suspension Event"), the covenants specifically listed under the following captions in this "Description of the Notes" section of this offering memorandum will not be applicable to the Notes (collectively, the "Suspended Covenants"):

(a) "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock";

(b) "—Limitation on Restricted Payments";

(c) "—Dividend and Other Payment Restrictions Affecting Subsidiaries";

(d) "—Asset Sales";

(e) "—Transactions with Affiliates"; and

(f) clause (d) of the first paragraph of "—Merger, Amalgamation, Consolidation or Sale of All or Substantially All Assets."

If and while the Parent Guarantor and the Restricted Subsidiaries are not subject to the Suspended Covenants, the Notes will be entitled to substantially less covenant protection. In the event that the Parent Guarantor and the Restricted Subsidiaries are not subject to the Suspended Covenants under the indenture for any period of time as a result of the foregoing, and on any subsequent date (the "Reversion Date") one or more of the Rating Agencies withdraw their Investment Grade Rating or downgrade the rating assigned to the Notes below an Investment Grade Rating, then the Parent Guarantor and the Restricted Subsidiaries will thereafter again be subject to the Suspended Covenants under the indenture with respect to future events. The period of time between the Covenant Suspension Event and the Reversion Date is referred to in this description as the "Suspension Period." The Issuer shall provide the Trustee with written notice of each Covenant Suspension Event or Reversion Date within five Business Days of the occurrence thereof. The Trustee will have no duty to monitor the ratings of the Notes or provide notice to the holders of Notes of any Covenant Suspension Event or Reversion Date.

On each Reversion Date, all Indebtedness Incurred, or Disqualified Stock or Preferred Stock issued, during the Suspension Period will be classified as having been Incurred or issued pursuant to the first paragraph of "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" below or one of the clauses set forth in the second paragraph of "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" below (to the extent such Indebtedness or Disqualified Stock or Preferred Stock would be permitted to be Incurred or issued thereunder as of the Reversion Date and after giving effect to Indebtedness Incurred or issued prior to the Suspension Period and outstanding on the Reversion Date). To the extent such Indebtedness or Disqualified Stock or Preferred Stock would not be so permitted to be Incurred or issued pursuant to the first or second paragraph of "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock," such Indebtedness or Disqualified Stock or Preferred Stock will be deemed to have been outstanding on the Issue Date, so that it is classified as permitted under clause (3) of the second paragraph under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock." Calculations made after the Reversion Date of the amount available to be made as Restricted Payments under "—Limitation on Restricted Payments" will be made as though the covenant described under "—Limitation on Restricted Payments" had been in effect since the Issue Date and prior to, but not during, the Suspension Period. Accordingly, Restricted Payments made during the Suspension Period will not reduce the amount available to be made as Restricted Payments under the first paragraph of "—Limitation on Restricted Payments." No Default or Event of Default will be deemed to have occurred on the Reversion Date as a result of any actions taken by the Parent Guarantor or the Restricted Subsidiaries during the Suspension Period. Within 30 days of such Reversion Date, the Parent Guarantor and the Issuer must comply with the terms of the covenant described under "—Future Guarantors."

For purposes of the "—Asset Sales" covenant, on the Reversion Date, the unutilized Excess Proceeds amount will be reset to zero.

There can be no assurance that the Notes will ever achieve or maintain Investment Grade Ratings.

Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock

The indenture will provide that:

(a) the Parent Guarantor shall not, and the Parent Guarantor shall not permit any Restricted Subsidiaries to, directly or indirectly, Incur any Indebtedness (including Acquired Indebtedness);

(b) the Parent Guarantor shall not issue any shares of Disqualified Stock; and

(c) the Parent Guarantor shall not permit any Restricted Subsidiaries to issue any shares of Preferred Stock (other than Preferred Stock of Restricted Subsidiaries held by the Parent Guarantor or a Restricted Subsidiary, so long as it is so held);

provided, however, that the Parent Guarantor may Incur Indebtedness (including Acquired Indebtedness) or issue shares of Disqualified Stock and any Restricted Subsidiary may Incur Indebtedness (including Acquired Indebtedness) or issue shares of Preferred Stock, in each case if the Fixed Charge Coverage Ratio of the Parent Guarantor for its most recently ended two full fiscal semi-annual periods for which internal financial statements are available immediately preceding the date on which such additional Indebtedness is Incurred or such Disqualified Stock or Preferred Stock is issued, as the case may be, would have been at least 2.25 to 1.00, determined on a *pro forma* basis (including a *pro forma* application of the net proceeds therefrom), as if the additional Indebtedness had been Incurred (together with any other Indebtedness incurred pursuant to the following paragraph), or the Disqualified Stock or Preferred Stock had been issued (together with any other Disqualified Stock or Preferred Stock issued pursuant to the following paragraph), as the case may be, and the application of proceeds therefrom had occurred at the beginning of such two full fiscal semi-annual periods.

The foregoing limitations shall not apply to:

(1) the Incurrence by the Parent Guarantor or any Restricted Subsidiary of Indebtedness under Credit Facilities in an aggregate principal amount at any one time outstanding under this clause (1) (with letters of credit being deemed to have a principal amount equal to the maximum potential liability of the Parent Guarantor and its Restricted Subsidiaries thereunder) not to exceed the greater of (x) US$500.0 million and (y) 25.0% of the Parent Guarantor's Total Assets determined as of the date of such incurrence; provided that any Indebtedness incurred under this clause (1) may be extended, replaced, refunded, refinanced, renewed or defeased (including through successive extensions, replacements, refundings, refinancings, renewals and defeasances) with new Indebtedness so long as the

principal amount (or accreted value, if applicable) of such new Indebtedness does not exceed the sum of (x) the principal amount (or accreted value, if applicable) of the Indebtedness being so extended, replaced, refunded, refinanced, renewed or defeased, plus (y) any accrued and unpaid interest on the Indebtedness being refinanced, plus (z) the amount of any tender premium or penalty or premium required to be paid under the terms of the instrument or documents governing such refinanced Indebtedness and any defeasance costs and any fees and expenses (including original issue discount, upfront fees or similar fees) incurred in connection with the incurrence of such new Indebtedness or the extension, replacement, refunding, refinancing, renewal or defeasance of such refinanced Indebtedness;

(2) the Incurrence by the Issuer and the Guarantors of Indebtedness represented by the Notes to be issued on the Issue Date (and any guarantee thereof (including the Guarantees)) (not including any additional notes or any guarantees thereof);

(3) Indebtedness existing on the Issue Date (other than Indebtedness described in clauses (1) and (2));

(4) Indebtedness Incurred by the Parent Guarantor or any Restricted Subsidiary constituting reimbursement obligations with respect to letters of credit and bank guarantees issued in the ordinary course of business, including without limitation letters of credit in respect of workers' compensation claims, social security benefits, health, disability or other benefits to employees or former employees or their families or property; casualty or liability insurance or self-insurance; performance guarantees; equipment leases; letters of credit in connection with the maintenance of, or pursuant to the requirements of, environmental or other permits or licenses from governmental authorities or other Indebtedness with respect to reimbursement type obligations regarding workers' compensation claims;

(5) Indebtedness arising from agreements of the Parent Guarantor or any Restricted Subsidiary providing for indemnification, adjustment of purchase price or similar obligations, in each case, Incurred in connection with any acquisition or disposition of any business, assets or a Subsidiary in accordance with the terms of the indenture, other than guarantees of Indebtedness Incurred by any Person acquiring all or any portion of such business, assets or Subsidiary for the purpose of financing such acquisition; provided that the maximum aggregate liability in respect of all such Indebtedness Incurred pursuant to this clause (5) will at no time exceed the gross proceeds actually received by the Parent Guarantor and any Restricted Subsidiaries in connection with such disposition;

(6) Indebtedness of the Parent Guarantor to a Restricted Subsidiary; provided that (except in respect of intercompany current liabilities Incurred in the ordinary course of business in connection with the cash management, tax and accounting operations of the Parent Guarantor and its Subsidiaries) any such Indebtedness owed to a Restricted Subsidiary that is not a Subsidiary Guarantor is subordinated in right of payment to the obligations of the Parent Guarantor under the Notes; provided, further, that any subsequent issuance or transfer of any Equity Interests or any other event that results in any such Restricted Subsidiary ceasing to be a Restricted Subsidiary or any other subsequent transfer of any such Indebtedness (except to the Parent Guarantor or another Restricted Subsidiary or any pledge of such Indebtedness constituting a Permitted Lien) shall be deemed, in each case, to be an Incurrence of such Indebtedness not permitted by this clause (6);

(7) shares of Preferred Stock of a Restricted Subsidiary issued to the Parent Guarantor or another Restricted Subsidiary; provided that any subsequent issuance or transfer of any Capital Stock or any other event which results in any Restricted Subsidiary that holds such shares of Preferred Stock of another Restricted Subsidiary ceasing to be a Restricted Subsidiary or any other subsequent transfer of any such shares of Preferred Stock (except to the Parent Guarantor or another Restricted Subsidiary or any pledge of such Preferred Stock constituting a Permitted Lien) shall be deemed, in each case, to be an issuance of shares of Preferred Stock not permitted by this clause (7);

(8) Indebtedness of a Restricted Subsidiary to the Parent Guarantor or another Restricted Subsidiary; provided that if a Subsidiary Guarantor Incurs such Indebtedness to a Restricted Subsidiary that is not the Issuer or a Guarantor (except in respect of intercompany current liabilities incurred in the ordinary course of business in connection with the cash management, tax and accounting operations of the Parent Guarantor and its Subsidiaries), such Indebtedness is subordinated in right of payment to the Guarantee of such Guarantor; provided, further, that any subsequent issuance or transfer of any Equity Interests or any other event that results in any Restricted Subsidiary holding such Indebtedness ceasing to be a Restricted Subsidiary or any other subsequent transfer of any such Indebtedness (except to the Parent Guarantor or another Restricted Subsidiary or any pledge of such Indebtedness constituting a Permitted Lien) shall be deemed, in each case, to be an Incurrence of such Indebtedness not permitted by this clause (8);

(9) Hedging Obligations entered into in the ordinary course of business and not for speculative purposes and extensions or replacements thereof;

(10) Indebtedness in respect of (i) surety and similar bonds and completion guarantees provided by the Parent Guarantor or any Restricted Subsidiary in the ordinary course of business and consistent with past practice or industry practice (in each case, other than for money borrowed), including guarantees or letters of credit functioning as any such bonds or obligations, and (ii) any customary cash management, cash pooling or netting or setting off arrangements with banks or other financial institutions, in each case, in the ordinary course of business;

(11) additional Indebtedness of the Parent Guarantor or any Restricted Subsidiary or Disqualified Stock of the Parent Guarantor or Preferred Stock of any Restricted Subsidiary in an aggregate principal amount or liquidation preference, that when aggregated with the principal amount or liquidation preference of all other Indebtedness, Disqualified Stock and Preferred Stock then outstanding and Incurred pursuant to this clause (11), together with any Indebtedness, Disqualified Stock or Preferred Stock Incurred to refund, refinance or defease such Indebtedness, Disqualified Stock or Preferred Stock, does not exceed the greater of (x) US$150.0 million and (y) 7.5% of the Parent Guarantor's Total Assets determined on the date of such incurrence (plus, in the case of any Indebtedness, Disqualified Stock or Preferred Stock Incurred to so refund, refinance or defease such Indebtedness, Disqualified Stock or Preferred Stock, the Additional Refinancing Amount) (it being understood that any Indebtedness Incurred pursuant to this clause (11) shall cease to be deemed Incurred or outstanding for purposes of this clause (11) but will be deemed Incurred for purposes of the first paragraph under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" from and after the first date on which the Parent Guarantor or the Restricted Subsidiary, as the case may be, could have Incurred such Indebtedness under the first paragraph under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" without reliance upon this clause (11));

(12) Indebtedness of the Parent Guarantor or any Restricted Subsidiaries:

   (i) Incurred for the purpose of financing all or any part of the purchase price, lease expense, charter expense, rental payments or cost of design, development, construction, transportation, installation, migration, expansion, improvement, replacement or repair of any FPSO, rig or production, processing, storage and/or transportation facility used or useful in the Oil and Gas Business; or

   (ii) represented by Financing Lease Obligations, mortgage financings or purchase money obligations or other Indebtedness, in each case, Incurred for the purpose of financing all or any part of the purchase price, lease expense, charter expense, rental payments or cost of design, development, construction, transportation, installation, migration, expansion or improvement of property, plant or equipment used in the Oil and Gas Business and any other capital expenses or operating expenses in relation thereto (including any reasonably related fees or expenses incurred in connection therewith), in an aggregate principal amount at any time outstanding under this clause (12)(ii), including all Refinancing Indebtedness incurred to extend, renew, refund, refinance, replace, exchange, defease or discharge any Indebtedness incurred pursuant to this clause (12)(ii), not to exceed the greater of (i) US$100.0 million and (ii) 5.5% of Total Assets at any time outstanding, in each case, whether such Indebtedness is incurred for the charter of, leasing of or direct purchase of or the purchase of the Capital Stock of any Person owning such property, plant or equipment or other assets (including any Indebtedness deemed to be incurred in connection with such purchase) (it being understood that any such Indebtedness may be incurred after the acquisition or purchase or the design, development, construction, transportation, installation, migration, expansion or the making of any improvement with respect to any such property, plant or equipment or other assets);

(13) any guarantee by the Parent Guarantor or any Restricted Subsidiary of Indebtedness of the Parent Guarantor or any Restricted Subsidiary so long as the Incurrence of such Indebtedness Incurred by the Parent Guarantor or such Restricted Subsidiary is permitted under the terms of the indenture; provided that (i) if such Indebtedness is by its express terms subordinated or *pari passu* in right of payment to the Notes or the Guarantee of such Guarantor, as applicable, any such guarantee with respect to such Indebtedness shall rank junior to or *pari passu*, as applicable, in right of payment to the Notes or such Guarantee, as applicable, at least to the same extent as such Indebtedness is subordinated or *pari passu*, as applicable, to the Notes or the Guarantee, as applicable and (ii) such guarantee is Incurred in accordance with, or not in contravention of, the covenant described under "—Future Guarantors" solely to the extent such covenant is applicable;

(14) the Incurrence by the Parent Guarantor or any Restricted Subsidiaries of Indebtedness or issuance by the Parent Guarantor of Disqualified Stock or issuance by a Restricted Subsidiary of Preferred Stock that serves to refund, refinance or defease any Indebtedness (other than intercompany Indebtedness) Incurred or Disqualified Stock or Preferred Stock issued as permitted under the first paragraph of this covenant or clauses (2), (3), (14) or (15) of this paragraph up to the outstanding principal amount (or, if applicable, the liquidation preference face amount, or the like) or, if greater, committed amount (only to the extent the committed amount could have been Incurred on the date of initial Incurrence) of such Indebtedness or Disqualified Stock or Preferred Stock, in each case at the time such Indebtedness was Incurred or Disqualified Stock or Preferred Stock was issued pursuant to the first paragraph of this covenant or clauses (2), (3), (14) or (15) of this paragraph, or any Indebtedness, Disqualified Stock or Preferred Stock Incurred to so refund, refinance or defease such Indebtedness, Disqualified Stock or Preferred Stock, in an aggregate principal amount (or if issued with original issue discount, an aggregate issue price) that is equal to or less than the sum of the aggregate principal amount (or if issued with original issue discount, the aggregate accreted value) then outstanding of the Indebtedness being refinanced (plus, without duplication, any additional Indebtedness Incurred to pay interest, premiums or defeasance costs required by the instruments governing such existing Indebtedness (whether such existing Indebtedness is redeemed pursuant to a tender offer, optional redemption or otherwise) and fees and expenses Incurred in connection therewith) (subject to the following proviso, "Refinancing Indebtedness") prior to its respective maturity; provided, however, that such Refinancing Indebtedness:

(i) has a Weighted Average Life to Maturity at the time such Refinancing Indebtedness is Incurred which is not less than the shorter of (x) the remaining Weighted Average Life to Maturity of the Indebtedness, Disqualified Stock or Preferred Stock being refunded, refinanced or defeased and (y) the Weighted Average Life to Maturity that would result if all payments of principal on the Indebtedness, Disqualified Stock and

Preferred Stock being refunded or refinanced that were due on or after the date that is one year following the last maturity date of any Notes then outstanding were instead due on such date (provided that this clause (i) will not apply to any refunding or refinancing of any First Priority Lien Obligations);

(ii) (A) if the final maturity date of the Indebtedness being refinanced is earlier than the last maturity date of any Notes then outstanding, the Refinancing Indebtedness has a final maturity date no earlier than the final maturity date of the Indebtedness being extended, renewed, refunded, discharged, refinanced, replaced or defeased or (B) if the final maturity date of the Indebtedness being refinanced is later than the last maturity date of any Notes then outstanding, the Refinancing Indebtedness has a final maturity date at least 91 days later than the last maturity date of any Notes then outstanding;

(iii) to the extent such Refinancing Indebtedness refinances (A) Indebtedness junior to the Notes or a Subsidiary Guarantee, as applicable, such Refinancing Indebtedness is junior to the Notes or the Subsidiary Guarantee, as applicable, on terms at least as favorable to the holders of Notes as those contained in the documentation governing the Indebtedness being refinanced, (B) Disqualified Stock or Preferred Stock, such Refinancing Indebtedness is Disqualified Stock or Preferred Stock or (C) unsecured Indebtedness, such Refinancing Indebtedness is unsecured Indebtedness; and

(iv) shall not include (A) Indebtedness of a Restricted Subsidiary that is not a Subsidiary Guarantor that refinances Indebtedness of the Issuer or a Guarantor, or (B) Indebtedness of the Parent Guarantor or a Restricted Subsidiary that refinances Indebtedness of an Unrestricted Subsidiary;

(15) (x) Indebtedness of the Parent Guarantor or any Restricted Subsidiary, Disqualified Stock issued by the Parent Guarantor or Preferred Stock issued by a Restricted Subsidiary, in each case Incurred in connection with an acquisition (provided that the aggregate principal amount of such Indebtedness, Disqualified Stock or Preferred Stock does not exceed the purchase price for such acquisition and any related fees and expenses), (y) Indebtedness of Persons that are acquired by the Parent Guarantor or any Restricted Subsidiary or merged, consolidated or amalgamated with or into the Parent Guarantor or any Restricted Subsidiary, Indebtedness is Incurred prior to the date of such transaction and not in contemplation of or in connection with such acquisition or (z) Indebtedness of a Person Incurred prior to the date on which such Person became a Restricted Subsidiary and not in contemplation of or in connection with such Person becoming a Restricted Subsidiary; provided that after giving *pro forma* effect to such transaction or series of transactions described in clauses (x), (y) or (z) of this clause (15), as applicable, either:

(i) the Parent Guarantor would be permitted to Incur at least US$1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of this covenant; or

(ii) the Fixed Charge Coverage Ratio of the Parent Guarantor would be equal to or greater than immediately prior to such transaction or series of transactions described in clauses (x), (y) or (z) of this clause (15);

(16) Indebtedness of the Parent Guarantor or any Restricted Subsidiary in the form of customer deposits and advance payments received in the ordinary course of business from customers for purchases in the ordinary course of business;

(17) Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument drawn against insufficient funds in the ordinary course of business;

(18) Indebtedness Incurred in respect of Permitted Invoice Discounting not to exceed an aggregate principal amount outstanding not to exceed the greater of (x) US$75.0 million and (y) 5.0% of Parent Guarantor's Total Assets at any time;

(19) guarantees by the Parent Guarantor or any Restricted Subsidiary granted to any trustee of any management equity plan or stock option plan or any other management or employee benefit or incentive plan or unit trust scheme approved by the Board of Directors of the Parent Guarantor, so long as the proceeds of the Indebtedness so guaranteed are used to purchase Equity Interests of the Parent Guarantor (other than Disqualified Stock); provided that the amount of any net cash proceeds from the sale of such Equity Interests of the Parent Guarantor will be excluded from clause (ii) of the definition of "Cumulative Credit" and will not be considered to be net cash proceeds from an Equity Offering for purposes of the provisions under "Optional Redemption;" and

(20) guarantees by the Parent Guarantor or any Restricted Subsidiary of pension fund obligations of the Parent Guarantor or any Restricted Subsidiary required by law or regulation.

Notwithstanding the foregoing, none of the Issuer or any Guarantor shall be permitted to Incur Indebtedness, in reliance on clauses (1) (other than pursuant to the RBL facility and the commitments thereunder as in effect on the Issue Date), (11) or (15) above, that is secured by a Lien (whether a first priority, second priority or otherwise) on the Collateral prior to the Brazilian Perfection Date.

For purposes of determining compliance with this covenant:

(i) in the event that an item of Indebtedness, Disqualified Stock or Preferred Stock (or any portion thereof) meets the criteria of more than one of the categories of permitted Indebtedness described in clauses (1) through (20) above or is entitled to be Incurred pursuant to the first paragraph of this covenant, then the Issuer shall, in its sole discretion, classify or reclassify, or later divide, classify or reclassify, such item of Indebtedness, Disqualified Stock or Preferred Stock (or any portion thereof) in any manner that complies with this covenant; provided that Indebtedness under the RBL facility shall be deemed Incurred under clause (1) above and may not later be reclassified;

(ii) if any Indebtedness denominated in U.S. dollars is exchanged, converted or refinanced into Indebtedness denominated in a foreign currency, then (in connection with such exchange, conversion or refinancing, and thereafter), the U.S. dollar amount limitations set forth in any of clauses (1) through (20) above with respect to such exchange, conversion or refinancing shall be deemed to be the amount of such foreign currency, as applicable, into which such Indebtedness has been exchanged, converted or refinanced at the time of such exchange, conversion or refinancing; and

(iii) if any Indebtedness denominated in a foreign currency is exchanged, converted or refinanced into Indebtedness denominated in U.S. dollars, then (in connection with such exchange, conversion or refinancing, and thereafter), the U.S. dollar amount limitations set forth in any of clauses (1) through (20) above with respect to such exchange, conversion or refinancing shall be deemed to be the amount of U.S. dollars into which such Indebtedness has been exchanged, converted or refinanced at the time of such exchange, conversion or refinancing.

The Parent Guarantor and Issuer will not Incur and will not permit any Subsidiary Guarantor to Incur any Indebtedness (including any Indebtedness permitted under this covenant) that is contractually subordinated in right of payment to any other Indebtedness of the Issuer or such Guarantor unless such Indebtedness is contractually subordinated in right of payment to the Notes Obligations on substantially identical terms; provided, however, that no Indebtedness will be deemed to be contractually subordinated in right of payment to any other Indebtedness solely by virtue of being unsecured or by virtue of being secured on a first or junior Lien basis.

Notwithstanding the foregoing, none of the Parent Guarantor or any Restricted Subsidiary will be permitted to Incur any Indebtedness secured by a first priority lien unless the principal amount of such Indebtedness is *pari passu* in right of payment with the Notes and all other Indebtedness secured by a first priority lien.

Accrual of interest, the accretion of accreted value, the payment of interest or dividends in the form of additional Indebtedness, Disqualified Stock or Preferred Stock, as applicable, amortization of original issue discount, the accretion of liquidation preference and increases in the amount of Indebtedness outstanding solely as a result of fluctuations in the exchange rate of currencies will not be deemed to be an Incurrence of Indebtedness, Disqualified Stock or Preferred Stock for purposes of this covenant. Guarantees of, or obligations in respect of letters of credit relating to, Indebtedness that is otherwise included in the determination of a particular amount of Indebtedness shall not be included in the determination of such amount of Indebtedness; provided that the Incurrence of the Indebtedness represented by such guarantee or letter of credit, as the case may be, was in compliance with this covenant.

For purposes of determining compliance with any U.S. dollar denominated restriction on the Incurrence of Indebtedness other than as provided in clauses (ii) and (iii) above, the U.S. dollar equivalent principal amount of Indebtedness denominated in a foreign currency shall be calculated based on the relevant currency exchange rate in effect on the date such Indebtedness was Incurred, in the case of term debt, or first committed or first Incurred (whichever yields the lower U.S. dollar equivalent), in the case of revolving credit debt.

Notwithstanding any other provision of this covenant, the maximum amount of Indebtedness that the Parent Guarantor and the Restricted Subsidiaries may Incur pursuant to this covenant shall not be deemed to be exceeded, with respect to any outstanding Indebtedness, solely as a result of fluctuations in the exchange rate of currencies.

Limitation on Restricted Payments

The indenture will provide that the Parent Guarantor shall not, and shall not permit any Restricted Subsidiaries to, directly or indirectly:

(a) declare or pay any dividend or make any distribution on account of any of the Parent Guarantor's or any Restricted Subsidiaries' Equity Interests, including any payment made in connection with any merger, amalgamation or consolidation involving the Parent Guarantor or any Restricted Subsidiary (other than (A) dividends or distributions payable solely in Equity Interests (other than Disqualified Stock) of the Parent Guarantor; or (B) dividends or distributions by a Restricted Subsidiary so long as, in the case of any dividend or distribution payable on or in respect of any class or series of securities issued by a Restricted Subsidiary that is not a Wholly Owned Restricted Subsidiary, the Parent Guarantor or a Restricted Subsidiary receives at least its pro rata share of such dividend or distribution in accordance with its Equity Interests in such class or series of securities);

(b) purchase or otherwise acquire or retire for value any Equity Interests of the Parent Guarantor held by Persons other than the Parent Guarantor or a Restricted Subsidiary;

(c) make any principal payment on, or redeem, repurchase, defease or otherwise acquire or retire for value, in each case prior to any scheduled repayment or scheduled maturity, any Subordinated Indebtedness of the Parent Guarantor, the Issuer or any Subsidiary Guarantor, any Other Second Lien Obligations or Notes owned by the Parent Guarantor or any Restricted Subsidiary thereof or any of their respective Affiliates, any Junior Lien Obligations of the Issuer or any Guarantor and any unsecured Indebtedness representing Indebtedness for borrowed money of the Issuer or any Guarantor (collectively, the "Restricted Indebtedness"), other than:

   (i) any intercompany Indebtedness between or among the Parent Guarantor and any of its Restricted Subsidiaries;

   (ii) the payment, redemption, repurchase, defeasance, acquisition or retirement for value of Subordinated Indebtedness, any Junior Lien Obligations and unsecured Indebtedness in anticipation of satisfying a sinking fund obligation, principal installment or final maturity, in each case due within one year of the date of such payment, redemption, repurchase, defeasance, acquisition or retirement; or

   (iii) Indebtedness permitted under clauses (7) and (9) of the second paragraph of the covenant described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock"; or

(d) make any Restricted Investment;

(all such payments and other actions set forth in clauses (a) through (d) above being collectively referred to as "Restricted Payments"), unless, at the time of and after giving effect to such Restricted Payment:

(A) no Default or Event of Default shall have occurred and be continuing or would occur as a consequence thereof;

(B) immediately after giving effect to such transaction on a *pro forma* basis, the Parent Guarantor could Incur US$1.00 of additional Indebtedness under the provisions of the first paragraph of the covenant described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock"; and

(C) such Restricted Payment, together with the aggregate amount of all other Restricted Payments made by the Parent Guarantor and any Restricted Subsidiaries after the Issue Date (including Restricted Payments permitted by clause (1) of the next succeeding paragraph, but excluding all other Restricted Payments permitted by the next succeeding paragraph) is less than the amount equal to the Cumulative Credit.

"Cumulative Credit" means the sum of (without duplication):

(i) 50% of the Consolidated Net Income of the Parent Guarantor for the period (taken as one accounting period) from the beginning of the semi-annual period commencing immediately prior to the Issue Date to the end of the Parent Guarantor's most recently ended semi-annual period for which internal financial statements are available at the time of such Restricted Payment (taken as one accounting period, the "Reference Period") (or in the case such Consolidated Net Income for such period is a deficit, minus 100% of such deficit), plus

(ii) 100% of the aggregate net proceeds, including cash and the Fair Market Value (as determined in good faith by the Parent Guarantor) of property or securities other than cash, in each case received by the Parent Guarantor after the Issue Date as a contribution to its common equity capital or that becomes a part of the capital of the Parent Guarantor through merger or amalgamation (in each case not including cash consideration payable by the Parent Guarantor or consideration related to the assumption of debt by the Parent Guarantor in connection with such merger or amalgamation) or from the issue or sale of Equity Interests of the Parent Guarantor or any direct or indirect parent of the Issuer (excluding Refunding Capital Stock (as defined below), Designated Preferred Stock and Disqualified Stock), including Equity Interests issued upon exercise of warrants or options (other than an issuance or sale to the Parent Guarantor or a Restricted Subsidiary), plus

(iii) 100% of the aggregate amount of contributions to the capital of the Parent Guarantor received in cash and the Fair Market Value (as determined in good faith by the Parent Guarantor) of property other than cash after the Issue Date (other than Refunding Capital Stock, Designated Preferred Stock and Disqualified Stock), plus

(iv) 100% of the principal amount of any Indebtedness, or the liquidation preference or maximum fixed repurchase price, as the case may be, of any Disqualified Stock of the Parent Guarantor or any Restricted Subsidiary issued after the Issue Date (other than Indebtedness or Disqualified Stock issued to a Restricted Subsidiary) that has been converted into or exchanged for Equity Interests in the Parent Guarantor, Issuer (other than Disqualified Stock) or any direct or indirect parent of the Issuer (provided in the case of any such parent (including the Parent Guarantor), such Indebtedness or Disqualified Stock is retired or extinguished), plus

(v) 100% of the aggregate amount received by the Parent Guarantor or any Restricted Subsidiary in cash and the Fair Market Value (as determined in good faith by the Parent Guarantor) of property other than cash received by the Parent Guarantor or any Restricted Subsidiary after the Issue Date from:

(A) the sale or other disposition (other than to the Parent Guarantor or a Restricted Subsidiary) of Restricted Investments made by the Parent Guarantor and any Restricted Subsidiaries and from repurchases and redemptions of such Restricted Investments from the Parent Guarantor and any Restricted Subsidiaries by any Person (other than the Parent Guarantor or any Restricted Subsidiaries) and from repayments of loans or advances, and releases of guarantees, which constituted Restricted Investments; and

(B) the sale (other than to the Parent Guarantor or a Restricted Subsidiary) of the Capital Stock of an Unrestricted Subsidiary, plus

(vi) 100% of any dividends or distributions received in cash by the Parent Guarantor or a Restricted Subsidiary after the Issue Date from an Unrestricted Subsidiary, to the extent that such dividends or distributions were not otherwise included in the Consolidated Net Income of the Issuer for such period, plus

(vii) in the event any Unrestricted Subsidiary has been redesignated as a Restricted Subsidiary after the Issue Date or has been merged, consolidated or amalgamated with or into, or transfers or conveys its assets to, or is liquidated into, the Parent Guarantor or a Restricted Subsidiary after the Issue Date, the Fair Market Value (as determined in good faith by the Parent Guarantor) of the Investment of the Parent Guarantor or any Restricted Subsidiaries in such Unrestricted Subsidiary (which, if the Fair Market Value of such Investment shall exceed US$25.0 million, shall be determined by the Board of Directors of the Parent Guarantor) at the time of such redesignation, combination or transfer (or of the assets transferred or conveyed, as applicable), to the extent such Investments reduced the Restricted Payments capacity under this clause (vii) and were not previously repaid or reduced.

The foregoing provisions shall not prohibit:

(1) the declaration and payment of any dividend or distribution on, or the redemption, repurchase, retirement or other acquisition of, any Equity Interests of the Parent Guarantor in an amount not to exceed 5.0% of the Market Capitalization of the Parent Guarantor determined on the date of such Restricted Payment; provided that after giving pro forma effect to such payment of dividend, distribution, redemption, repurchase, retirement or other acquisition of Equity Interests of the Parent Guarantor, the Net Leverage Ratio of the Parent Guarantor is equal to or less than 1.0;

(2) the payment of any dividend or distribution or the consummation of any irrevocable redemption within 60 days after the date of declaration thereof, if at the date of declaration or the giving notice of such irrevocable redemption, as applicable, such payment would have complied with the provisions of the indenture;

(3) (i) the redemption, repurchase, retirement or other acquisition of any Equity Interests ("Retired Capital Stock") or Restricted Indebtedness of the Issuer, any direct or indirect parent of the Issuer or any Guarantor in exchange for, or out of the proceeds of, the substantially concurrent sale of, Equity Interests of the Issuer or any direct or indirect parent of the Issuer or contributions to the equity capital of the Parent Guarantor or Issuer (other than any Disqualified Stock or any Equity Interests sold to a Subsidiary of the Parent Guarantor or the Issuer) (collectively, including any such contributions, "Refunding Capital Stock"), and

(ii) the declaration and payment of dividends on the Retired Capital Stock out of the proceeds of the substantially concurrent sale (other than to a Subsidiary of the Parent Guarantor or the Issuer) of Refunding Capital Stock;

(4) (i) the redemption, repurchase, defeasance or other acquisition or retirement of Subordinated Indebtedness of the Issuer or any Guarantor made by exchange for, or out of the proceeds of the substantially concurrent sale of, new Refinancing Indebtedness of the Issuer or a Guarantor in respect of such Subordinated Indebtedness that is Incurred in accordance with clause (14) of the covenant described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" so long as such Indebtedness is subordinated to the Notes or the related Subsidiary Guarantee, as the case may be, at least to the same extent as such Subordinated Indebtedness so purchased, exchanged, redeemed, repurchased, defeased, acquired or retired for value;

(ii) the redemption, repurchase, defeasance or other acquisition or retirement of Other Second Lien Obligations or Notes of the Issuer or any Guarantor made by exchange for, or out of the proceeds of the substantially concurrent sale of, new Refinancing Indebtedness of the Issuer or a Guarantor in respect of such Other Second Lien Obligations which is Incurred in accordance with clause (14) of the covenant described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" so long as such Indebtedness constitutes Other Second Lien Obligations, Notes, Junior Lien Obligations, Subordinated Indebtedness or unsecured Indebtedness;

(iii) the redemption, repurchase, defeasance or other acquisition or retirement of Junior Lien Obligations of the Issuer or any Guarantor made by exchange for, or out of the proceeds of the substantially concurrent sale of, new Refinancing Indebtedness of the Issuer or any Guarantor in respect of such Junior Lien Obligations that is Incurred in accordance with clause (14) of the covenant described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" so long as such Indebtedness constitutes Junior Lien Obligations, Subordinated Indebtedness or unsecured Indebtedness; or

(iv) the redemption, repurchase, defeasance or other acquisition or retirement of unsecured Indebtedness representing Indebtedness for borrowed money of the Issuer or any Guarantor made by exchange for, or out of the proceeds of the substantially concurrent sale of, new Refinancing Indebtedness of the Issuer or a Guarantor in respect of such unsecured Indebtedness that is Incurred in accordance with clause (14) of the covenant described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" so long as such Indebtedness constitutes Subordinated Indebtedness or unsecured Indebtedness;

(5) a Restricted Payment to pay for the repurchase, retirement or other acquisition for value since of Equity Interests of the Parent Guarantor or any Restricted Subsidiary held by any present or former employee, director or manager of the Parent Guarantor or any Restricted Subsidiary pursuant to any management equity plan or stock option plan or any other management or employee benefit plan or other agreement or arrangement; provided, however, that the aggregate Restricted Payments made under this clause (5) do not exceed US$7.5 million in any calendar year, with unused amounts in any calendar year being permitted to be carried over to succeeding calendar years subject to a maximum of US$15.0 million in any calendar year; provided, further, however, that such amount in any calendar year may be increased by an amount not to exceed:

(i) the cash proceeds received by the Parent Guarantor or any Restricted Subsidiary from the sale of Equity Interests (other than Disqualified Stock) of the Parent Guarantor to members of management, directors, managers or employees of the Parent Guarantor and any Restricted Subsidiaries after the Issue Date (provided that the amount of such cash proceeds utilized for any such repurchase, retirement, other acquisition or dividend will not increase the amount available for Restricted Payments under clause (iii) of the definition of "Cumulative Credit"), plus

(ii) the cash proceeds of key man life insurance policies received by the Parent Guarantor or the Restricted Subsidiaries after the Issue Date;

provided, that the Issuer may elect to apply all or any portion of the aggregate increase contemplated by clauses (i) and (ii) above in any calendar year;

(6) the declaration and payment of regularly scheduled or accrued dividends or distributions to holders of any class or series of Disqualified Stock of the Parent Guarantor or Preferred Stock of any Restricted Subsidiaries issued or Incurred on or after the Issue Date in accordance with the Fixed Charge Coverage Ratio test set forth under the first paragraph of the covenant described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock";

(7) the repurchase, redemption or other acquisition or retirement for value since the Issue Date of any Equity Interests of the Parent Guarantor or any Restricted Subsidiary held by any of Parent Guarantor's or any Restricted Subsidiaries' current or former directors or employees in connection with the exercise or vesting of any equity compensation (including, without limitation, stock options, restricted stock and phantom stock) or made in order to satisfy the Parent Guarantor's or such Restricted Subsidiary's tax withholding obligation with respect to such exercise or vesting;

(8) other Restricted Payments in an aggregate amount, when taken together with all other Restricted Payments made pursuant to this clause (8) since the Issue Date, not to exceed the greater of (x) US$50.0 million and (y) 2.5% of the Parent Guarantor's Total Assets determined on the date of such Restricted Payment;

(9) repurchases of Equity Interests deemed to occur upon exercise of stock options or warrants if such Equity Interests represent a portion of the exercise price of such options or warrants;

(10) Restricted Payments by the Parent Guarantor or any Restricted Subsidiary to allow the payment of cash in lieu of the issuance of fractional shares upon the exercise of options or warrants or upon the conversion or exchange of Equity Interests of any such Person;

(11) the repurchase, redemption or other acquisition or retirement for value of any Subordinated Indebtedness at a purchase price not greater than (i) 101% of the principal amount of such Subordinated Indebtedness in the event of a Change of Control or (ii) 100% of the principal amount of such Subordinated Indebtedness in the event of an Asset Sale, in each case plus accrued and unpaid interest, pursuant to provisions similar to those described under the captions "—Change of Control" and "—Certain Covenants—Asset Sales" in each case in connection with any change of control or asset sale offer required by the terms of such Subordinated Indebtedness; provided that all Notes tendered by holders of the Notes in connection with a Change of Control Offer or Asset Sale Offer, as applicable, have been repurchased, redeemed or acquired for value and (x) in the case of a Change of Control, the Issuer has first complied with and fully satisfied its obligations under the provisions described under "—Change of Control" or (y) in the case of an Asset Sale, the Issuer has complied with and fully satisfied its obligations in accordance with the covenant under "—Certain Covenants—Asset Sales"; and

(12) Restricted Payments by a Restricted Subsidiary to the holders of its Equity Interests on a pro rata basis;

provided, however, that at the time of, and after giving effect to, any Restricted Payment permitted under clauses (1), (5), (7), (8) and (11) of this covenant, no Default or Event of Default shall have occurred and be continuing or would occur as a consequence thereof; provided, further, that any Restricted Payments made with property other than cash shall be calculated using the Fair Market Value on the date of the Restricted Payment (as determined in good faith by the Parent Guarantor) of such property.

Notwithstanding the foregoing, no Restricted Payment may be made under any provision of this covenant prior to the Brazilian Perfection Date.

For purposes of determining compliance with this covenant, in the event that any Restricted Payment or Investment (or a portion thereof) meets the criteria of more than one of the categories of Restricted Payments described in the preceding clauses (1) through (12) above and/or one or more of the clauses contained in the definition of "Permitted Investments," the Issuer will, in its sole discretion, be entitled to divide or classify (or later divide, classify or reclassify), in whole or in part, such Restricted Payment or Investment (or any portion thereof) among clauses (1) through (12) and/or one or more clauses contained in the definition of "Permitted Investments" in a manner that otherwise complies with this covenant.

As of the Issue Date, all of the Subsidiaries of the Parent Guarantor shall be Restricted Subsidiaries. The Parent Guarantor shall not permit any Unrestricted Subsidiary to become a Restricted Subsidiary except pursuant to the definition of "Unrestricted Subsidiary." For purposes of designating any Restricted Subsidiary as an Unrestricted Subsidiary, all outstanding Investments by the Parent Guarantor and the Restricted Subsidiaries (except to the extent repaid) in the Subsidiary so designated shall be deemed to be Restricted Payments in an amount determined as set forth in the last sentence of the definition of "Investments." Such designation shall only be permitted if a Restricted Payment or Permitted Investment in such amount would be permitted at such time and if such Subsidiary otherwise meets the definition of an Unrestricted Subsidiary.

Dividend and Other Payment Restrictions Affecting Subsidiaries

The indenture will provide that the Parent Guarantor shall not, and shall not permit any Restricted Subsidiaries to, directly or indirectly, create or otherwise cause or suffer to exist or become effective any consensual encumbrance or consensual restriction on the ability of any Restricted Subsidiary to:

(a) pay dividends or make any other distributions to the Parent Guarantor or any Restricted Subsidiaries (1) on its Capital Stock or (2) with respect to any other interest or participation in, or measured by, its profits; or

(b) pay any Indebtedness owed to the Parent Guarantor or any Restricted Subsidiaries;

(c) make loans or advances to the Parent Guarantor or any Restricted Subsidiaries; or

(d) sell, lease or transfer any of its properties or assets to the Parent Guarantor or any Restricted Subsidiaries;

except in each case for such encumbrances or restrictions existing under or by reason of:

(1) (i) contractual encumbrances or restrictions pursuant to agreements in effect on the Issue Date and (ii) contractual encumbrances or restrictions pursuant to the RBL facility and the other RBL Facility Documents and, in each case, any similar contractual encumbrances effected by any amendments, modifications, restatements, renewals, supplements, refundings, replacements or refinancings of such agreements or instruments;

(2) the indenture, the Notes, Security Documents or the Subsidiary Guarantees;

(3) applicable law or any applicable rule, regulation or order;

(4) any agreement or other instrument governing Indebtedness or Capital Stock of a Person acquired by the Parent Guarantor or any Restricted Subsidiary that was in existence at the time of such acquisition (but not created in contemplation of, in connection with, or to provide all or any portion of the funds or credit support utilized to consummate such acquisition), which encumbrance or restriction is not applicable to any Person, or the properties or assets of any Person, other than the Person and its Subsidiaries, or the property or assets of the Person and its Subsidiaries, so acquired;

(5) contracts or agreements for the sale of assets, including any restriction with respect to a Restricted Subsidiary imposed pursuant to an agreement entered into for the sale or disposition of the Capital Stock or assets of such Restricted Subsidiary;

(6) Secured Indebtedness otherwise permitted to be Incurred pursuant to the covenants described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" and "—Liens" that limit the right of the debtor to dispose of the assets securing such Indebtedness;

(7) restrictions on cash or other deposits or net worth imposed by customers under contracts entered into in the ordinary course of business;

(8) customary provisions in joint venture agreements and other similar agreements entered into in the ordinary course of business;

(9) purchase money obligations for property acquired and Financing Lease Obligations in the ordinary course of business that impose restrictions of the nature discussed in clause (d) in the list above on the property so acquired;

(10) customary provisions contained in leases, licenses and other similar agreements entered into in the ordinary course of business;

(11) in the case of clause (d) of the first paragraph of this covenant, any encumbrance or restriction that restricts in a customary manner the subletting, assignment or transfer of any property or asset that is subject to a lease (including leases governing leasehold interests or Farm-In Agreements or Farm-Out Agreements relating to leasehold interests in Oil and Gas Properties), license or similar contract, or the assignment or transfer of any such lease (including leases governing leasehold interests or Farm-In Agreements or Farm-Out Agreements relating to leasehold interests in Oil and Gas Properties), license (including without limitations, licenses of intellectual property) or other contracts;

(12) other Indebtedness, Disqualified Stock or Preferred Stock (a) of the Issuer or any Guarantor or (b) of any Restricted Subsidiary that is not a Subsidiary Guarantor so long as such encumbrances and restrictions contained in any agreement or instrument will not materially affect the Issuer's ability to make anticipated principal or interest payments on the Notes (as determined in good faith by the Issuer); provided that in the case of each of clauses (a) and (b), such Indebtedness, Disqualified Stock or Preferred Stock is permitted to be Incurred subsequent to the Issue Date pursuant to the covenant described under "—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock";

(13) an Investment otherwise permitted by the indenture;

(14) any customary encumbrances or restrictions imposed pursuant to any agreement of the type described in the definition of "Permitted Business Investment"; or

(15) any encumbrances or restrictions of the type referred to in clauses (a), (b), (c) or (d) above imposed by any amendments, modifications, restatements, renewals, increases, supplements, refundings, replacements or refinancings of the contracts, instruments or obligations referred to in clauses (1) through (14) above; provided that such amendments, modifications, restatements, renewals, increases, supplements, refundings, replacements or refinancings are, in the good faith judgment of the Issuer, no more restrictive with respect to such dividend and other payment restrictions than those contained in the dividend or other payment restrictions prior to such amendment, modification, restatement, renewal, increase, supplement, refunding, replacement or refinancing.

For purposes of determining compliance with this covenant, (1) the priority of any Preferred Stock in receiving dividends or liquidating distributions prior to dividends or liquidating distributions being paid on common stock shall not be deemed a restriction on the ability to make distributions on Capital Stock and (2) the subordination of loans or advances made to the Parent Guarantor or a Restricted Subsidiary to other Indebtedness Incurred by the Parent Guarantor or any Restricted Subsidiary shall not be deemed a restriction on the ability to make loans or advances.

Asset Sales

The indenture will provide that the Parent Guarantor shall not, and shall not permit any Restricted Subsidiary to, cause or make an Asset Sale, unless (x) the Parent Guarantor or any Restricted Subsidiaries, as the case may be, receives consideration at the time of such Asset Sale at least equal to the Fair Market Value (if the consideration for such Asset Sale is less than or equal to US$20.0 million, as determined in good faith by the Parent Guarantor or if the consideration for such Asset Sale exceeds US$20.0 million, as determined by in good faith by the Board of Directors of the Parent Guarantor as evidenced by the resolution of such Board of Directors and certified by an Officers' Certificate delivered to the Trustee, which the Trustee shall be entitled to conclusively rely on) of the assets sold or otherwise disposed of, and (y) at least 75% of the aggregate consideration received in such Asset Sale by the Parent Guarantor or such Restricted Subsidiary, as the case may be, since the Issue Date (on a cumulative basis), is in the form of cash or Cash Equivalents; provided that the amount of:

(a) any liabilities (as shown on the Parent Guarantor's or a Restricted Subsidiary's most recent balance sheet or in the notes thereto) of the Parent Guarantor or any Restricted Subsidiary (other than liabilities that are by their terms subordinated to the Notes or any Subsidiary Guarantee) that are assumed by the transferee of any such assets or that are otherwise canceled or terminated in connection with the transaction with such transferee;

(b) any Notes or other obligations or other securities received by the Parent Guarantor or such Restricted Subsidiary from such transferee that are converted by the Parent Guarantor or such Restricted Subsidiary into cash within 180 days of the receipt thereof (to the extent of the cash received);

(c) with respect to any Asset Sale of Oil and Gas Properties by the Parent Guarantor or any Restricted Subsidiary, the costs and expenses related to the exploration, development, completion or production of such Oil and Gas Properties and activities related thereto agreed to be assumed by the transferee (or an Affiliate thereof); and

(d) any Designated Non-cash Consideration received by the Parent Guarantor or any Restricted Subsidiary in such Asset Sale having an aggregate Fair Market Value (as determined in good faith by the Parent Guarantor), taken together with all other Designated Non-cash Consideration received pursuant to this clause (d) that is at that time outstanding, not to exceed 2.5% of the Parent Guarantor's Total Assets at the time of the receipt of such Designated Non-cash Consideration (with the Fair Market Value of each item of Designated Non-cash Consideration being measured at the time received and without giving effect to subsequent changes in value),

shall be deemed to be Cash Equivalents for the purposes of this provision.

Within 360 days of the Parent Guarantor's or any Restricted Subsidiary's receipt of the Net Proceeds of any Asset Sale, the Parent Guarantor or such Restricted Subsidiary may apply the Net Proceeds from such Asset Sale, at its option:

(1) to repay (i) Indebtedness constituting First Priority Lien Obligations, (ii) Notes Obligations, (iii) other Pari Passu Indebtedness so long as the Net Proceeds from such Asset Sale are with respect to assets not constituting Collateral or (iv) Other Second Lien Obligations (provided that if the Parent Guarantor, Issuer or any Subsidiary Guarantor shall so reduce Other Second Lien Obligations under this clause (iv) (which for the avoidance of doubt will not constitute Indebtedness under clauses (i), (ii) or (iii)), the Issuer will equally and ratably reduce Obligations under the Notes as provided under "Optional Redemption," through open-market purchases (provided that such purchases are at or above 100% of the principal amount thereof or, in the event that the Notes were issued with significant original issue discount, 100% of the accreted value thereof) or by making an offer (in accordance with the procedures set forth below for an Asset Sale Offer) to all holders to purchase at a purchase price equal to 100% of the principal amount thereof (or, in the event that the Notes were issued with significant original issue discount, 100% of the accreted value thereof), plus accrued and unpaid interest and additional interest, if any, the pro rata principal amount of Notes, in each case other than Indebtedness owed to the Issuer or an Affiliate of the Issuer);

(2) to make an Investment in any one or more businesses (provided that if such Investment is in the form of the acquisition of Capital Stock of a Person, such acquisition results in such Person becoming a Restricted Subsidiary of the Parent Guarantor), assets, or property or capital expenditures, in each case (a) used or useful in the Oil and Gas Business or (b) that replace the properties and assets that are the subject of such Asset Sale; provided that if the assets that were disposed of in the Asset Sale constituted Collateral, the assets acquired must also be Collateral;

(3) make a capital expenditure of assets used or useful in the Oil and Gas Business or any other capital expenditures for maintenance, repair or improvement of existing properties and assets; or

(4) any combination of the foregoing,

provided, that the requirements of clauses (2) and (3) of this paragraph shall be deemed to be satisfied if a bona fide binding commitment to make the Investment or expenditure referred to therein is entered into by the Parent Guarantor or any Restricted Subsidiaries with a Person other than an Affiliate of the Issuer within the time period specified in the preceding paragraph and such Net Proceeds are subsequently applied in accordance with such commitment within 270 days following the date such commitment is entered into.

Any Net Proceeds from any Asset Sale that are not applied as provided and within the time period set forth in the second paragraph of this covenant (it being understood that any portion of such Net Proceeds used to make an offer to purchase Notes, as described in clause (1) of the paragraph above, shall be deemed to have been invested whether or not such offer is accepted) will be deemed to constitute "Excess Proceeds." When the aggregate amount of Excess Proceeds exceeds US$50.0 million, the Issuer shall make an offer to all holders of Notes (and, at the option of the Issuer, to holders of any Other Second Lien Obligations) (an "Asset Sale Offer") to purchase the maximum principal amount of Notes (and such Other Second Lien Obligations), that is at least US$200,000 and an integral multiple of US$1,000 in excess thereof that may be purchased out of the Excess Proceeds at an offer price in cash in an amount equal to 100% of the principal amount thereof (or, in the event the Notes or such Other Second Lien Obligations was issued with significant original issue discount, 100% of the accreted value thereof), plus accrued and unpaid interest and additional interest, if any (or, in respect of such Other Second Lien Obligations, such lesser price, if any, as may be provided for by the terms of such Other Second Lien Obligations), to the date fixed for the closing of such offer, in accordance with the procedures set forth in the indenture. The Issuer will commence an Asset Sale Offer with respect to Excess Proceeds within 10 Business Days after the date that Excess Proceeds exceeds US$50.0 million by delivering the notice required pursuant to the terms of the indenture, with a copy to the Trustee. To the extent that the aggregate amount of Notes (and such Other Second Lien Obligations) tendered pursuant to an Asset Sale Offer is less than the Excess Proceeds, the Issuer may use any remaining Excess Proceeds for any purpose that is not prohibited by the indenture. If the aggregate principal amount of Notes (and such Other Second Lien Obligations) surrendered by holders thereof exceeds the amount of Excess Proceeds, the Issuer, upon determination by the Issuer of the aggregate principal amount to be selected, shall select the Notes to be purchased in the manner described below. Upon completion of any such Asset Sale Offer, the amount of Excess Proceeds shall be reset at zero.

Pending the final application of any such Net Proceeds pursuant to this covenant, the Parent Guarantor or such Restricted Subsidiary may temporarily reduce Indebtedness under a revolving credit facility, if any, or otherwise invest such Net Proceeds in any manner not prohibited by the indenture.

The Issuer will comply with the requirements of Rule 14e-1 under the Exchange Act and any other securities laws and regulations to the extent such laws or regulations are applicable in connection with the repurchase of the Notes pursuant to an Asset Sale Offer. To the extent that the provisions of any securities laws or regulations conflict with the Asset Sale provisions of the indenture, the Issuer will comply with the applicable securities laws and regulations and shall not be deemed to have breached its obligations described in the Asset Sale provisions of the indenture by virtue thereof.

If more Notes (and such Pari Passu Indebtedness) are tendered pursuant to an Asset Sale Offer than the Issuer is required to purchase, selection of such Notes for purchase shall be made by the Issuer in compliance with the requirements of the SGX-ST, for so long as the Notes are listed on such exchange (and the Issuer shall notify a Trust Officer of the Trustee of any such change in listing), or if such Notes are not so listed, on a pro rata basis, to the extent practicable, by lot or by such other method as the Issuer shall deem fair and appropriate (and in such manner as complies with the requirements of DTC, if applicable); provided that no Notes of US$200,000 or less shall be purchased in part. Selection of such Pari Passu Indebtedness shall be made pursuant to the terms of such Pari Passu Indebtedness.

Notices of an Asset Sale Offer shall be mailed by the Issuer by first class mail, postage prepaid, or otherwise delivered in accordance with the applicable procedures of DTC, at least 10 but not more than 30 days before the purchase date to each holder of Notes at such holder's registered address, with a copy to the Trustee. If any note is to be purchased in part only, any notice of purchase that relates to such note shall state the portion of the principal amount thereof that has been or is to be purchased.

The RBL facility contains, and agreements that the Parent Guarantor and its Restricted Subsidiaries enter into in the future may contain, prohibitions of certain events, including events that would constitute a Change of Control or an Asset Sale and including repurchases of or other prepayments in respect of the Notes. The exercise by the holders of Notes of their right to require the Issuer to repurchase the Notes upon a Change of Control or an Asset Sale could cause a default under these other agreements, even if the Change of Control or Asset Sale itself is not due to the financial effect of such repurchases on the Issuer or otherwise. In the event a Change of Control or Asset Sale occurs at a time when the Issuer is prohibited from purchasing Notes, the Parent Guarantor or applicable Restricted Subsidiary could seek the consent of the applicable lenders to the purchase of Notes or could attempt to refinance the Indebtedness that contain such prohibitions. If the Parent Guarantor or applicable Restricted Subsidiary, as the case may be, does not obtain a consent to repay that Indebtedness, the Issuer will remain prohibited from purchasing Notes. In that case, the Issuer's failure to purchase tendered Notes would constitute an Event of Default under the indenture, which could, in turn, constitute a default under other Indebtedness of the Parent Guarantor or a Restricted Subsidiary. Finally, the Issuer's ability to pay cash to the holders of Notes upon a repurchase may be limited by the Issuer's then existing financial resources. See "Risk Factors—Risks Relating to the Notes and Security—We may not be able to repurchase the Notes upon a change of control."

Transactions with Affiliates

The indenture will provide that the Parent Guarantor shall not, and shall not permit any Restricted Subsidiaries to, directly or indirectly, make any payment to, or sell, lease, transfer or otherwise dispose of any of its properties or assets to, or purchase any property or assets from, or enter into or make or amend any transaction or series of transactions, contract, agreement, understanding, loan, advance or guarantee with, or for the benefit of, any Affiliate of the Issuer (each of the foregoing, an "Affiliate Transaction") involving aggregate consideration in any single transactions or series of related transactions in excess of US$10.0 million, unless:

(a) such Affiliate Transaction is on terms that are not less favorable to the Parent Guarantor or the relevant Restricted Subsidiary than those that could have been obtained in a comparable transaction by the Parent Guarantor or such Restricted Subsidiary with an unrelated Person; and

(b) with respect to any Affiliate Transaction or series of related Affiliate Transactions involving aggregate consideration in excess of US$35.0 million, the Issuer delivers to the Trustee a resolution adopted in good faith by the majority of the disinterested members of the Board of Directors of the Parent Guarantor, approving such Affiliate Transaction and set forth in an Officers' Certificate delivered by the Issuer to the Trustee, which the Trustee shall be entitled to conclusively rely on, certifying that such Affiliate Transaction complies with this covenant and that such Affiliate Transactions has been approved by a majority of the disinterested members of the Parent Guarantor's Board of Directors.

The foregoing provisions will not apply to the following:

(1) transactions between or among the Parent Guarantor and/or any Restricted Subsidiaries (or any entity that becomes a Restricted Subsidiary as a result of such transactions);

(2) Restricted Payments permitted by the provisions of the covenant described under "—Limitation on Restricted Payments" and Permitted Investments (other than Permitted Investments contemplated by clauses (c), (g), (h), (j) or (n) of the definition thereof);

(3) the payment of reasonable and customary fees and reimbursement of expenses paid to, and indemnity provided on behalf of, officers, directors, managers or employees of the Parent Guarantor or any Restricted Subsidiary as determined in good faith by the Board of Directors of the Parent Guarantor or Restricted Subsidiary, as applicable;

(4) transactions in which the Parent Guarantor or any Restricted Subsidiary, as the case may be, delivers to the Trustee a letter from an Independent Financial Advisor stating that such transaction is fair to the Parent Guarantor or such Restricted Subsidiary from a financial point of view or meets the requirements of clause (a) of the preceding paragraph;

(5) payments or loans (or cancellation of loans) to officers, directors, managers or employees of the Parent Guarantor or any Restricted Subsidiary, which are approved by a majority of the Board of Directors of the Issuer in good faith;

(6) the performance of obligations of the Parent Guarantor or any Restricted Subsidiary under the terms of any written agreement to which the Parent Guarantor or any Restricted Subsidiary is a party and as in effect as of the Issue Date or any amendment thereto (so long as any such agreement together with all amendments thereto, taken as a whole, is not more disadvantageous to the holders of the Notes in any material respect than the original agreement as in effect on the Issue Date as determined in good faith by the Parent Guarantor's of Directors) or any transaction contemplated thereby as determined in good faith by the Issuer;

(7) (a) transactions with customers, clients, suppliers or purchasers or sellers of goods or services, or transactions otherwise relating to the purchase or sale of goods or services, in each case in the ordinary course of business and otherwise in compliance with the terms of the indenture, which are fair to the Parent Guarantor and Restricted Subsidiaries in the reasonable determination of the Board of Directors or the senior management of the Parent Guarantor, or are on terms at least as favorable as might reasonably have been obtained at such time from an unaffiliated party or (b) any transaction with a joint venture or similar entity that would constitute an Affiliate Transaction solely because the Parent Guarantor or any of its Restricted Subsidiaries owns any equity interest in or otherwise controls such joint venture or similar entity;

(8) the issuance of Equity Interests (other than Disqualified Stock) of the Parent Guarantor to any Person;

(9) the issuances of securities or other payments, awards or grants in cash, securities or otherwise pursuant to, or the funding of, employment arrangements, stock option and stock ownership plans or similar employee benefit plans approved by the Board of Directors of the Parent Guarantor in good faith;

(10) any contribution to the capital of the Parent Guarantor;

(11) transactions permitted by, and complying with, the provisions of the covenant described under "—Merger, Amalgamation, Consolidation or Sale of All or Substantially All Assets";

(12) transactions between the Parent Guarantor or any Restricted Subsidiaries and any Person, a director or manager of which is also a director or manager of the Issuer or any direct or indirect parent of the Issuer and such director is the sole cause for such Person being deemed an Affiliate of the Parent Guarantor or any Restricted Subsidiary; provided, however, that such director or manager abstains from voting as a director or manager of the Issuer or such direct or indirect parent, as the case may be, on any matter involving such other Person; provided, further, that such transaction is not with an Unrestricted Subsidiary;

(13) pledges of Equity Interests of Unrestricted Subsidiaries; and

(14) any employment agreements entered into by the Parent Guarantor or any of its Restricted Subsidiaries in the ordinary course of business.

Liens

The indenture will provide that the Parent Guarantor will not, and will not permit any Restricted Subsidiary to, directly or indirectly, create, Incur, assume, cause or suffer to exist any Lien of any kind (except Permitted Liens) on any asset or property (whether now owned or hereafter acquired) of the Parent Guarantor or such Restricted Subsidiary securing Indebtedness of the Parent Guarantor or any Restricted Subsidiary; provided that Permitted Liens may not Incurred be pursuant to clauses (e)(ii) (other than to secure obligations under the RBL facility as in effect on the Issue Date), (x), (gg) or (ii) of the definition of Permitted Liens, in each case to the extent such Lien is on the Collateral prior to the Brazilian Perfection Date.

For purposes of determining compliance with this covenant, (A) a Lien securing an item of Indebtedness need not be permitted solely by reference to one category of Permitted Liens described in the definition of "Permitted Liens" or pursuant to the first paragraph of this covenant but may be permitted in part under any combination thereof and (B) in the event that a Lien securing an item of Indebtedness, Disqualified Stock or Preferred Stock (or any portion thereof) meets the criteria of one or more of the categories of Permitted Liens described in the definition of "Permitted Liens," the Issuer shall, in its sole discretion, classify or reclassify, or later divide, classify or reclassify, such Lien securing such item of Indebtedness (or any portion thereof) in any manner that complies with this covenant and will only be required to include the amount and type of such Lien or such item of Indebtedness secured by such Lien in one of the clauses of the definition of "Permitted Liens" and such Lien securing such item of Indebtedness will be treated as being Incurred or existing pursuant to only one of such clauses.

With respect to any Lien securing Indebtedness that was permitted to secure such Indebtedness at the time of the Incurrence of such Indebtedness, such Lien shall also be permitted to secure any Increased Amount of such Indebtedness. The "Increased Amount" of any Indebtedness means any increase in the amount of such Indebtedness in connection with any accrual of interest, the accretion of accreted value, the amortization of original issue discount, the payment of interest in the form of additional Indebtedness with the same terms or in the form of common stock of the Parent Guarantor, the payment of dividends on Preferred Stock in the form of additional shares of Preferred Stock of the same class, accretion of original issue discount or liquidation preference and increases in the amount of Indebtedness outstanding solely as a result of fluctuations in the exchange rate of currencies or increases in the value of property securing Indebtedness described in clause (c) of the definition of "Indebtedness."

Reports and Other Information

The Issuer will provide to the Trustee and each holder of Notes or will provide to the Trustee for forwarding or making available to each holder of Notes upon request, without cost to such holder of Notes or to the Trustee: (1) as soon as available after the end of each fiscal year (and, in any event, within 120 days after the close of such fiscal year), annual reports of the Parent Guarantor in English, including (a) audited financial statements (containing a consolidated balance sheet as of the end of such fiscal year and immediately preceding fiscal year and consolidated statements of comprehensive income, financial position, changes in equity and cash flows for such fiscal year and the immediately preceding fiscal year) with a report thereon by an internationally recognized independent firm of chartered accountants, (b) an operating and financial review of the audited financial statements, including a discussion of the results of operations, including a discussion of financial condition and liquidity and capital resources, and a discussion of material commitments and contingencies and critical accounting policies, (c) a description of the business, management and shareholders of the Parent Guarantor, all material affiliate transactions, indebtedness and material contractual arrangements, including all material debt instruments, and (d) material recent developments, (2) as soon as available (and, in any event, within 75 days after the close of the first six months in each fiscal year) interim semi-annual reports of the Parent Guarantor in English, containing (a) a condensed consolidated balance sheet as of the end of each interim period covered thereby and as of the end of the immediately preceding fiscal year and condensed consolidated statements of comprehensive income, financial position, changes in equity and cash flows for each interim period covered thereby and for the comparable period of the immediately preceding fiscal year, (b) an operating and financial review of the condensed consolidated balance sheet and condensed consolidated statements of comprehensive income, financial position, changes in equity and cash flows, including a discussion of the results of operations, including a discussion of financial condition and liquidity and capital resources, and a discussion of material commitments and contingencies and critical accounting policies, (c) a description of the business, management and shareholders of the Parent Guarantor, all material affiliate transactions, indebtedness and material contractual arrangements, including all material debt instruments, and (d) material recent developments and (3) as soon as available quarterly reports required to be filed by the Parent Guarantor under the rules of the ASX, containing production rate, production volume, sales volume weighted average net realized sales price, sales revenue, sales cash proceeds, capital expenditure, closing cash and cash equivalents, closing debt, closing net cash and cash equivalents, closing number of ordinary shares on issue, lost time injury rate and total recordable incident rate for each interim period covered thereby and for the immediately preceding comparable period. So long as the Issuer is required to file or furnish annual or interim reports with the ASX, the content of such reports shall be deemed to satisfy the requirements set forth in clauses (1)(b)-(d) and (2)(b)-(d) to the extent that such reports comply with the requirements of the ASX. The Issuer need not provide those annual or interim reports to the Trustee and each holder of Notes if and to the extent that the Parent Guarantor files or furnishes those reports with the ASX and those reports are available on the ASX website within the time periods referred to in clauses (1), (2) and (3) above.

If the Issuer has designated any Subsidiary of the Parent Guarantor as an Unrestricted Subsidiary, then the annual and semi-annual information required pursuant to clauses (1) and (2) of the first paragraph of this covenant shall include a reasonably detailed presentation, either on the face of the financial statements, in the footnotes thereto or in any discussion and analysis of financial condition and results of operations, of the financial condition and results of operations of the Parent Guarantor and its Restricted Subsidiaries separate from the financial condition and results of operations of such Unrestricted Subsidiaries.

The Issuer will also, for so long as any Notes remain "restricted" securities, furnish or cause to be furnished to the holders of the Notes, beneficial owners of the Notes, securities analysts and prospective investors upon request the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act.

The Issuer will also hold a presentation once every 12 months (which may be by video or audio conference or other electronic format), for all holders of the Notes, prospective investors and securities analysts to discuss such financial information and, prior to the date of each such conference call, will announce the time and date of such conference call and either include all information necessary to access the call or inform holders of the Notes, prospective investors and securities analysts how they can obtain such information, including, without limitation, the applicable password or login information (if applicable). Such presentation may be the same presentation held for lenders under the RBL facility and other holders of Indebtedness of the Parent Guarantor.

The Trustee shall have no liability or responsibility for the content, filing or timeliness of any report delivered or filed under or in connection with the indenture or the transactions contemplated thereby. Delivery of such reports, information and documents to the Trustee is for informational purposes only, and the Trustee's receipt thereof shall not constitute constructive notice of any information contained therein or determinable from information contained therein, including the Issuer's compliance with any of its covenants under the indenture (as to which the Trustee is entitled to rely exclusively on Officers' Certificates).

Notice

The indenture contains certain notice provisions, including notice requirements to the Trustee, the holders of the Notes and, to the extent required, to the SGX-ST or such other exchange on which the Notes may be listed. Neither the failure to give any notice to a particular holder of Notes nor any defect in a notice given to a particular holder of Notes will affect the sufficiency of notice given to another holder of Notes.

Further Assurances with Respect to Collateral

In accordance with the terms of the indenture and the applicable Security Documents, the Senior Lien Intercreditor Documents and Second Lien Pari Passu Intercreditor Agreement, the Issuer and the Guarantors will take all action necessary to (i) ensure that each of the Security Documents and any related ancillary documents are promptly and duly filed publicly with all appropriate authorities in Brazil, England and Australia, as the case may be (or any other applicable jurisdiction with respect to any after-acquired property), and (ii) ensure that all such Security Documents are properly recorded, all fees in connection therewith paid, and all ancillary actions to be taken in connection therewith taken as applicable, in each case in accordance with the terms of the Security Documents. Notwithstanding the preceding sentence, if any filing, recording or other actions are not required by the terms of the security documents entered into in connection with the Syndicated Credit Facility, then such filing, recording or other action will not be required by the Security Documents. The Security Documents and/or the indenture will provide that the pledgor, the Issuer or any Guarantor shall, at the sole expense of the pledgor, the Issuer or any Guarantor, as applicable, shall, at its sole expense and subject to the Agreed Security Principles and Senior Lien Intercreditor Documents, do all acts that may be reasonably necessary to deliver evidence to the Trustee that the Collateral was duly created, is enforceable and perfected second priority Liens (subject to the registrations and perfections requirements provided under the Security Documents) on the Collateral within the timeframe described above under "—Security," subject to Permitted Liens. Pursuant to the terms of the Senior Lien Intercreditor Documents, Second Lien Pari Passu Intercreditor Agreement and the Security Documents, upon instruction of the intercreditor agent to the applicable collateral agent and upon subsequent request of such applicable collateral agent, the Trustee or a majority of the holders of the Notes, the pledgor, the Issuer and any Guarantor shall, at the sole expense of the pledgor, the Issuer or any Guarantor, as applicable, shall, at their sole expense, execute, acknowledge and deliver such documents and instruments (including the filing of financing statements or amendments or continuations thereto) and take such other actions that may be necessary to assure, perfect, transfer and confirm the rights conveyed by the Security Documents, to the extent permitted by applicable law and subject to the Agreed Security Principles and the Senior Lien Intercreditor Documents. This paragraph is subject to certain limitations described under "—Limitations on securities collateral."

Notwithstanding anything to the contrary contained herein or in applicable law, neither the Trustee nor the Common Security Agent shall have responsibility for (i) preparing, recording, filing, rerecording or re-refiling any financing statement, perfection statement, continuation statement or other instrument (including the Security Documents) in any public office or for otherwise ensuring the perfection or maintenance of any security interest granted pursuant to, or contemplated by, the Indenture and the Security Documents; or (ii) for monitoring or confirming the Issuer's or the Parent Guarantor's compliance with any of their respective covenants, including but not limited to, covenants regarding the granting, perfection or maintenance of any security interest.

Merger, Amalgamation, Consolidation or Sale of All or Substantially All Assets

The indenture will provide that the Parent Guarantor and Issuer may not, directly or indirectly, consolidate, amalgamate or merge with or into or wind up or convert into (whether or not the Parent Guarantor or Issuer is the surviving Person), or sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of its properties or assets in one or more related transactions, to any Person unless:

(a) the Parent Guarantor or the Issuer, as applicable, is the surviving person or the Person formed by or surviving any such consolidation, amalgamation, merger, winding up or conversion (if other than the Parent Guarantor or Issuer) or to which such sale, assignment, transfer, lease, conveyance or other disposition will have been made is a corporation, partnership or limited liability company organized or existing under the laws of Australia or any state or territory thereof with respect to the Parent Guarantor or the United States, any state thereof, the District of Columbia, or any territory thereof with respect to the Issuer (the Parent Guarantor, Issuer or such Person, as the case may be, being herein called the "Successor Company");

(b) the Successor Company (if other than the Parent Guarantor or Issuer) expressly assumes all the obligations of the Parent Guarantor or Issuer, as applicable, under the Notes, the indenture and the Security Documents pursuant to supplemental indentures; provided that unless such Successor Company to the Issuer is a corporation or limited liability company, a corporate co-issuer of the Notes will be added to the indenture by supplemental indenture;

(c) immediately after giving *pro forma* effect to such transaction (and treating any Indebtedness which becomes an obligation of the Successor Company, or any Restricted Subsidiary as a result of such transaction as having been Incurred by the Successor Company or such Restricted Subsidiary at the time of such transaction) no Default or Event of Default shall have occurred and be continuing;

(d) immediately after giving *pro forma* effect to such transaction and any related financing transaction, as if such transactions had occurred at the beginning of the applicable two full fiscal semi-annual periods (and treating any Indebtedness that becomes an obligation of the Successor Company, or any Restricted Subsidiary as a result of such transaction as having been Incurred by the Successor Company, or such Restricted Subsidiary at the time of such transaction), either

    (i) the Parent Guarantor or the Successor Company to the Parent Guarantor, as applicable, would be permitted to Incur at least US$1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock"; or

    (ii) the Fixed Charge Coverage Ratio for the Parent Guarantor or the Successor Company to the Parent Guarantor, as applicable, would be no less than such ratio for the Parent Guarantor immediately prior to such transaction;

(e) in the case of a transaction involving the Issuer, if the Issuer is not the Successor Company, each Guarantor, unless it is the other party to the transactions described above, shall have by supplemental indenture confirmed that its Guarantee shall apply to such Person's obligations under the indenture and the Notes;

(f) the Successor Company shall have delivered to the Trustee an Officers' Certificate and an Opinion of Counsel, each stating that such consolidation, merger, amalgamation or transfer and such supplemental indentures (if any) comply with the indenture; and

(g) any Collateral owned by or transferred to the Successor Company (if other than the Parent Guarantor or Issuer) continues to constitute Collateral under the indenture, Notes, Guarantees and Security Documents, subject to the parity Liens, except as permitted by the indenture.

The Successor Company to the Parent Guarantor or the Issuer (if other than the Parent Guarantor or the Issuer), as the case may be, will succeed to, and be substituted for, the Parent Guarantor or the Issuer, as applicable, under the indenture and the Notes, and in such event the Issuer shall be automatically released and discharged from its obligations under the indenture and the Notes, but in the case of a lease of all or substantially all of its assets, (x) the Issuer will not be released from the obligation to pay the principal and interest and premium, if any, on the Notes and (y) the Parent Guarantor will not be released from the obligations under its Guarantee. Notwithstanding the foregoing clause (d) of the preceding paragraph of this covenant, (i) any Restricted Subsidiary may merge, consolidate or amalgamate with or transfer all or part of its properties and assets to the Parent Guarantor or to a Restricted Subsidiary and (ii) the Parent Guarantor or Issuer may merge, consolidate or amalgamate with an Affiliate incorporated solely for the purpose of reincorporating the Parent Guarantor or Issuer, as applicable, in another state of the United States, the District of Columbia or any territory of the United States with respect to the Issuer or state of Australia or any territory of Australia with respect to the Parent Guarantor or may convert into a corporation, partnership or limited liability company, so long as the amount of Indebtedness of the Parent Guarantor and the Restricted Subsidiaries is not increased thereby.

The indenture will further provide that, subject to certain provisions in the indenture governing release of a Subsidiary Guarantee upon the sale, disposition, exchange or other transfer of a Restricted Subsidiary of the Parent Guarantor that is a Subsidiary Guarantor, no Subsidiary Guarantor shall, and the Parent Guarantor shall not permit any Subsidiary Guarantor to, consolidate, amalgamate or merge with or into or wind up into (whether or not such Subsidiary Guarantor is the surviving Person), or sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of its properties or assets in one or more related transactions to, any Person unless:

(1) either (i) such Subsidiary Guarantor is the surviving Person or the Person formed by or surviving any such consolidation, amalgamation or merger (if other than such Subsidiary Guarantor) or to which such sale, assignment, transfer, lease, conveyance or other disposition shall have been made is a company, corporation, partnership or limited liability company (in the case of such Subsidiary Guarantor) or similar entity organized or existing under the laws of the jurisdictions in which such Subsidiary Guarantor is organized (such Subsidiary Guarantor or such Person, as the case may be, being herein called the "Successor Subsidiary Guarantor") and the Successor Subsidiary Guarantor (if other than such Subsidiary Guarantor) expressly assumes all the obligations of such Subsidiary Guarantor under the indenture and the Notes or the Subsidiary Guarantee and the Security Documents, as applicable, pursuant to a supplemental indenture, or (ii) such sale or disposition or consolidation, amalgamation or merger is not in violation of the covenant described above under the caption "—Certain Covenants—Asset Sales";

(2) the Successor Subsidiary Guarantor (if other than such Subsidiary Guarantor) shall have delivered or caused to be delivered to the Trustee an Officers' Certificate and an Opinion of Counsel, each stating that such consolidation, amalgamation, merger or transfer and such supplemental indenture (if any) comply with the indenture; and

(3) any Collateral owned by or transferred to the Successor Subsidiary Guarantor (if other than the Subsidiary Guarantor) continues to constitute Collateral under the indenture, Notes, Guarantees and Security Documents, subject to the parity Liens, except as permitted by the indenture.

Subject to certain limitations described in the indenture, the Successor Subsidiary Guarantor (if other than such Subsidiary Guarantor) will succeed to, and be substituted for, such Subsidiary Guarantor under the indenture and the Notes or the Subsidiary Guarantee and the Security Documents, as applicable, and such Subsidiary Guarantor will automatically be released and discharged from its obligations under the indenture, its Subsidiary Guarantee and the Security Documents. Notwithstanding the foregoing, (1) a Subsidiary Guarantor may merge, amalgamate or consolidate with an Affiliate incorporated solely for the purpose of reincorporating such Subsidiary Guarantor in another state of the United States, the District of Columbia or any territory of the United States, state of Australia or any territory of Australia or state of Brazil or any territory of Brazil or may convert into a limited liability company, corporation, partnership or similar entity organized or existing under the laws of another state of the United States, the District of Columbia or any territory of the United States, state of Australia or any territory of Australia or state of Brazil or any territory of Brazil so long as the amount of Indebtedness of such Subsidiary Guarantor is not increased thereby and (2) a Subsidiary Guarantor may merge, amalgamate or consolidate with the Parent Guarantor, Issuer or another Subsidiary Guarantor.

In addition, notwithstanding the foregoing, a Subsidiary Guarantor may consolidate, amalgamate or merge with or into or wind up into, liquidate, dissolve, or sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of its properties or assets to the Parent Guarantor, Issuer or another Subsidiary Guarantor.

Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve "all or substantially all" of the property and assets of a Person.

Defaults

An "Event of Default" with respect to the Notes will be defined in the indenture as:

(a) a default in any payment of interest (including any additional interest) or Additional Amounts, if any, on the Notes when the same becomes due and payable and such default continues for a period of 30 days;

(b) a default in the payment of principal or premium, if any, on the Notes when due at its Stated Maturity, upon optional redemption, upon required repurchase, upon declaration or otherwise;

(c) failure by the Issuer or any Guarantor to comply with the provisions described under the caption "—Certain Covenants—Merger, Amalgamation, Consolidation or Sale of All or Substantially All Assets";

(d) failure by the Parent Guarantor or any of the Restricted Subsidiaries for 60 days after written notice given by the Trustee or the holders of not less than 30% in principal amount of the Notes of such series then outstanding (with a copy to a Trust Officer of the Trustee) to comply with its other obligations, covenants or agreements (other than a default referred to in clauses (a), (b) or (c) above) contained in such Notes, the indenture or the Security Documents;

(e) the failure by the Parent Guarantor, Issuer or any Significant Subsidiary (or any group of Subsidiaries that together would constitute a Significant Subsidiary) to pay any principal of or interest or premium, if any, on Indebtedness (including where the payment of which is guaranteed by the Parent Guarantor or any Restricted Subsidiaries) (other than Indebtedness owing to the Parent Guarantor or a Restricted Subsidiary), whether such Indebtedness now exists or is created after the date of the indenture, within any applicable grace period after final maturity or such failure results in the acceleration of any such Indebtedness by the holders thereof prior to its express maturity because of a default, in each case, if (A) the total amount of such Indebtedness together with the principal amount of any other such Indebtedness unpaid or accelerated exceeds US$50.0 million or its foreign currency equivalent or (B) such Indebtedness is subject to the Senior Lien Intercreditor Agreement (the "cross acceleration provision");

(f) certain events of bankruptcy, insolvency or reorganization of the Parent Guarantor, Issuer or a Significant Subsidiary (or any group of Subsidiaries that together would constitute a Significant Subsidiary);

(g) failure by the Parent Guarantor or any Significant Subsidiary to pay final judgments aggregating in excess of US$50.0 million or its foreign currency equivalent (net of any amounts that are covered by enforceable insurance policies issued by reputable and solvent carriers where such liability is acknowledged by such carriers in writing), which judgments are not discharged, waived or stayed for a period of 60 days (the "judgment default provision");

(h) the Guarantee of any Guarantor with respect to the Notes is held in any judicial proceeding to be unenforceable or invalid or ceases to be in full force and effect (except as contemplated by the terms thereof) or the Parent Guarantor, Issuer or any Subsidiary Guarantor denies or disaffirms its obligations set forth in or arising under the indenture, the Notes or the Guarantees and such Default continues for 10 days;

(i) unless such Liens have been released in accordance with the provisions of the indenture, the Security Documents or the Senior Lien Intercreditor Documents, Liens in favor of the holders of the Notes with respect to Collateral with a Fair Market Value in excess of US$25.0 million cease to be valid or enforceable or perfected, subject only to Permitted Liens and the terms of the Senior Lien Intercreditor Documents, and where such Default is susceptible to cure, it continues for 30 days, or the Issuer shall assert or any Guarantor shall assert, in any pleading in any court of competent jurisdiction, that any such security interest is invalid or unenforceable or otherwise denies or disaffirms its obligations set forth or arising under the Security Documents and, in the case of any Subsidiary Guarantor, the Parent Guarantor fails to cause such Subsidiary Guarantor to rescind such assertions within 30 days after the Parent Guarantor has actual knowledge of such assertions;

(j) all or substantially all of the undertaking, assets and revenues of the Parent Guarantor or any Restricted Subsidiary are condemned, seized or otherwise appropriated by any Person acting under the authority of any national, regional or local government or the Parent Guarantor or any Restricted Subsidiary is prevented by any such Person from exercising normal control over all or substantially all of the undertaking, assets and revenues of the Parent Guarantor or any Restricted Subsidiary; or

(k) the Issuer or any Guarantor fails to complete any step required in connection with perfection or to perfect a second priority security interest in any Collateral described under "—Security—Brazilian Security" within the applicable periods as required pursuant to the covenants described under "—Security—Brazilian Security—Equity Interests," "—Security—Brazilian Security—Concessions," "—Security—Brazilian Security—Credit Receivables and Contractual Rights" or "—Security—Brazilian Security—Equipment."

The foregoing will constitute Events of Default whatever the reason for any such Event of Default and whether it is voluntary or involuntary or is effected by operation of law or pursuant to any judgment, decree or order of any court or any order, rule or regulation of any administrative or governmental body.

However, a default under clause (d) above will not constitute an Event of Default with respect to the Notes until the Trustee or the holders of 30% in principal amount of outstanding Notes (with a copy to a Trust Officer of the Trustee) notify the Issuer of the Default and the Parent Guarantor or Issuer does not cure such Default within the time specified in clause (d) after receipt of such notice; provided that a notice of Default may not be given with respect to any action taken, and reported publicly or to holders, more than two years prior to such notice of Default.

For the avoidance of doubt, the Trustee shall be entitled to conclusively rely on any notice of Default, notice of acceleration or instruction to the Trustee to provide a notice of Default, notice of acceleration or take any other action (a "Noteholder Direction") delivered to it in accordance with the indenture or verify any statements in any Officers' Certificate delivered to it. The Trustee shall have no liability to the Issuer, any holder or any other Person in acting in good faith on a Noteholder Direction.

If an Event of Default with respect to the Notes (other than a Default relating to certain events of bankruptcy, insolvency or reorganization of the Parent Guarantor or Issuer) occurs and is continuing, the Trustee or the holders of at least 30% in principal amount of the outstanding Notes (with a copy to a Trust Officer of the Trustee) by notice to the Issuer may declare the principal of, premium, if any, and accrued but unpaid interest and any Additional Amounts on all Notes to be due and payable. Upon the Trustee or the holders of at least 30% in principal amount of the outstanding Notes providing notification to the Issuer of such a declaration, such principal and interest will be due and payable immediately. If an Event of Default relating to certain events of bankruptcy, insolvency or reorganization of the Parent Guarantor, any Restricted Subsidiary of the Parent Guarantor that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary occurs, the principal of, premium, if any, and interest on all the Notes shall ipso facto become and be immediately due and payable without any declaration or other act on the part of the Trustee or any holders. The holders of a majority in principal amount of the outstanding Notes by notice to a Trust Officer of the Trustee may rescind an acceleration and its consequences if the rescission would not conflict with any judgment or decree and if all existing Events of Default with respect to such Notes have been cured or waived except nonpayment of Additional Amounts, principal or interest or premium on the Notes that has become due solely because of acceleration. No such rescission shall affect any subsequent Default or impair any right consequent thereto.

In the event of any Event of Default specified in clause (e) of the first paragraph above, such Event of Default and all consequences thereof (excluding, however, any resulting payment default) will be annulled, waived and rescinded, automatically and without any action by the Trustee or the holders of the Notes, if within 20 days after such Event of Default arose the Issuer delivers an Officers' Certificate to the Trustee stating that (x) the Indebtedness or guarantee that is the basis for such Event of Default has been discharged or (y) the holders thereof have rescinded or waived the acceleration, notice or action (as the case may be) giving rise to such Event of Default or (z) the default that is the basis for such Event of Default has been cured, it being understood that in no event shall an acceleration of the principal amount of the Notes as described above be annulled, waived or rescinded upon the happening of any such events.

In case an Event of Default with respect to the Notes occurs and is continuing, the Trustee will be under no obligation to exercise any of the rights or powers under the indenture or the Security Documents at the written request or direction of any of the holders of the Notes unless such holders have offered to the Trustee indemnity or security satisfactory to it against any loss, liability or expense. Except to enforce the right to receive payment of principal, premium (if any), interest or Additional Amounts when due, no holder of a note of such series may pursue any remedy with respect to the indenture, the Notes or the Security Documents unless:

(1) such holder has previously given a Trust Officer of the Trustee written notice that an Event of Default is continuing,

(2) holders of at least 30% in principal amount of the outstanding Notes have requested in writing that the Trustee pursue the remedy,

(3) such holders have offered the Trustee security or indemnity satisfactory to it against any loss, liability or expense,

(4) the Trustee has not complied with such request within 60 days after the receipt of the request and the offer of security or indemnity, and

(5) the holders of a majority in principal amount of the outstanding Notes have not given the Trustee a written direction inconsistent with such request within such 60-day period.

Subject to certain restrictions, the holders of a majority in principal amount of outstanding Notes are given the right to direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on the Trustee. The Trustee, however, may refuse to follow any direction that conflicts with law or the indenture or that the Trustee determines is unduly prejudicial to the rights of any other holder (it being understood that the Trustee does not have an affirmative duty to ascertain whether or not such actions or forbearances are unduly prejudicial to such holder) or that would involve the Trustee in personal liability. Prior to taking any action under the indenture, the Trustee will be entitled to indemnification satisfactory to it in its sole discretion against all liabilities, losses and expenses caused by taking or not taking such action.

The indenture will provide that if a Default occurs and is continuing and is actually known to a Trust Officer, the Trustee must mail, or deliver electronically if held by the Depository, to each holder of the Notes notice of the Default within the later of 90 days after it occurs or 30 days after it is actually known to a Trust Officer or written notice of it is received by the Trustee at the Corporate Trust Office. Except in the case of a Default in the payment of principal of, premium (if any), interest or Additional Amounts on any note, the Trustee may withhold notice if and so long as it in good faith determines that withholding notice is in the interests of the noteholders. In addition, the Issuer and Guarantors are required to deliver to the Trustee, annually, a certificate indicating whether the signers thereof know of any Default that occurred during the previous year and whether such Default is continuing and, if so, proposed steps to cure such Default. The Issuer and Guarantors also are required to deliver to a Trust Officer of the Trustee, within 30 days after the occurrence thereof, written notice of any event that would constitute a Default of Event of Default, their status and what action the Issuer is taking or proposes to take in respect thereof.

Amendments and Waivers

Subject to certain exceptions, the indenture, the Notes, the Guarantees, the Security Documents, the Senior Lien Intercreditor Documents, the Second Lien Pari Passu Intercreditor Agreement and/or any Customary Intercreditor Agreements may be amended with the consent of the holders of at least a majority in principal amount of the Notes then outstanding voting as a single class (including consents obtained in connection with a tender offer or exchange for the Notes) and any past default or compliance with any provisions may be waived with the consent of the holders of at least a majority in principal amount of the then outstanding Notes. However, without the consent of each holder of an outstanding note affected, no amendment may, among other things:

(a) reduce the amount of Notes whose holders must consent to an amendment, supplement or waiver;

(b) reduce the rate of or change the time for payment of interest on any note (other than with respect to a Change of Control Offer or Asset Sale Offer);

(c) reduce the principal of or change the Stated Maturity of any note (other than with respect to a Change of Control Offer or Asset Sale Offer);

(d) reduce the premium payable (if any) upon the redemption of any note of such series or change the time at which any note of such series may be redeemed as described under "—Optional Redemption" above;

(e) make any note payable in money other than that stated in such note;

(f) expressly subordinate the Notes or any Guarantee thereof to any other Indebtedness of the Issuer or any Guarantor;

(g) impair the contractual right of any holder of Notes to receive payment of principal of, premium, if any, and interest on such holder's Notes on or after the due dates therefor or to institute suit for the enforcement of any payment on or with respect to such holder's Notes;

(h) make any change in the amendment provisions that require the consent of each holder of Notes or in the waiver provisions; or

(i) make any change in the provisions dealing with the application of proceeds of Collateral in the Senior Lien Intercreditor Documents, any Customary Intercreditor Agreement, the Security Documents or the indenture that would adversely affect the holders of Notes of such series in any material respect.

Except as expressly provided by the indenture or the Security Documents, without the consent of the holders of at least 66.67% in aggregate principal amount of the then outstanding Notes, no amendment may modify or release the Guarantee of the Parent Guarantor or any Restricted Subsidiary. Without the consent of the holders of at least 66.67% in aggregate principal amount of the then outstanding Notes, no amendment or waiver may release all or substantially all of the Collateral from the Lien of the Security Documents.

Without the consent of any holder, the Issuer and the Trustee may amend the indenture, the Notes, the Guarantees, the Security Documents, the Senior Lien Intercreditor Documents, the Second Lien Pari Passu Intercreditor Agreement and/or a Customary Intercreditor Agreement:

(1) to cure any ambiguity, omission, mistake, defect or inconsistency;

(2) to provide for the assumption by a Successor Company of the obligations of the Parent Guarantor or Issuer under the indenture, the Notes of such series, the Security Documents, the Senior Lien Intercreditor Documents and/or a Customary Intercreditor Agreement;

(3) to provide for the assumption by a Successor Subsidiary Guarantor (with respect to any Subsidiary Guarantor), as the case may be, of the obligations of a Subsidiary Guarantor under the indenture, its Subsidiary Guarantee, the Security Documents, the Senior Lien Intercreditor Documents and/or a Customary Intercreditor Agreement;

(4) to provide for uncertificated notes in addition to or in place of certificated notes;

(5) to add a Subsidiary Guarantee or Collateral with respect to the Notes as provided in the indenture or the other Security Documents, as applicable;

(6) to release Collateral or a Subsidiary Guarantee as permitted by the indenture, the Security Documents, the Senior Lien Intercreditor Documents or any Customary Intercreditor Agreement;

(7) to add additional secured creditors holding First Priority Lien Obligations, Other Second Lien Obligations or Junior Lien Obligations so long as such obligations are not prohibited by the indenture;

(8) to comply with any requirement of the SEC in connection with qualifying or maintaining the qualification of the indenture under the TIA;

(9) to make any change that would provide any additional rights or benefits to the holders of Notes or does not adversely affect the rights of any holder of Notes;

(10) to provide for the issuance of additional notes in accordance with the limitations set forth in the indenture as of the date of the indenture, which shall have terms substantially identical in all material respects to the initial notes and shall be treated, together with any outstanding initial notes, as a single issue of Securities;

(11) to effect any provision of the indenture; or

(12) to conform the text of the Indenture, the Notes or the Guarantees to the corresponding provision of this "Description of the Notes" to the extent that such provision in this "Description of the Notes" was intended to be a verbatim recitation of a provision of the Indenture, the Notes and the Guarantees.

The Senior Lien Intercreditor Documents or any Customary Intercreditor Agreement may be amended without the consent of any holder of Notes, the Trustee in connection with the permitted entry into the Senior Lien Intercreditor Documents of any class of additional secured creditors holding Other Second Lien Obligations, First Priority Lien Obligations or Junior Lien Obligations to effectuate such entry into the Senior Lien Intercreditor Documents or any Customary Intercreditor Agreement and to make the lien of such class equal and ratable with, as applicable, the lien of the First Priority Lien Obligations, the Other Second Lien Obligations or Junior Lien Obligations, in each case, to the extent such First Priority Lien Obligations, Other Second Lien Obligations or Junior Lien Obligations are expressly permitted to be incurred pursuant to the indenture.

The consent of the noteholders is not necessary under the indenture to approve the particular form of any proposed amendment. It is sufficient if such consent approves the substance of the proposed amendment. After an amendment, supplement or waiver under the indenture becomes effective, the Issuer is required to send to the holders a notice briefly describing such amendment. However, the failure to give such notice to all the holders, or any defect in the notice, will not impair or affect the validity of the amendment.

Limited Condition Transactions

Notwithstanding anything to the contrary in the indenture, in connection with any action being taken solely in connection with a Limited Condition Transaction, for purposes of (a) determining compliance with any provision of the indenture that requires the calculation of the Fixed Charge Coverage Ratio or Gross Secured Leverage Ratio, (b) determining whether a Default or Event of Default shall have occurred and be continuing or (c) testing availability under exceptions or baskets set forth in the indenture (including exceptions or baskets measured as a percentage of Total Assets), in each case at the option of the Issuer (any such option, an "LCT Election"), with such option to be exercised on or prior to the date of execution of the definitive agreements with respect to such Limited Condition Transaction, the date of determination of whether any such action shall be permitted under the indenture shall be deemed to be the date the definitive agreements for such Limited Condition Transaction are entered into (each, an "LCT Test Date") and if, after such ratio and other provisions are measured on a *pro forma* basis after giving effect to such Limited Condition Transaction and the other Specified Transactions to be entered into in connection therewith (including any incurrence of Indebtedness and the use of proceeds thereof) as if they occurred at the beginning of the applicable two full fiscal semi-annual reference periods ending prior to the applicable LCT Test Date, the Parent Guarantor or the applicable Restricted Subsidiary could have taken such action on the relevant LCT Test Date in compliance with such ratio and provisions, such ratio and provisions shall be deemed to have been complied with. For the avoidance of doubt, (x) if any of such ratio or baskets are exceeded (or, with respect to the Fixed Charge Coverage Ratio, not reached) as a result of fluctuations in such ratio or basket (including due to fluctuations in EBITDAX of the Parent Guarantor or fluctuations in EBITDAX of the target of any Limited Condition Transaction) at or prior to the consummation of the relevant Limited Condition Transaction, such ratio and other provisions will not be deemed to have been exceeded (or, with respect to the Fixed Charge Coverage Ratio, not reached) as a result of such fluctuations solely for purposes of determining whether the Limited Condition Transaction is permitted hereunder and (y) such ratio and other provisions shall not be tested at the time of consummation of such Limited Condition Transaction or related Specified Transactions. If the Issuer has made an LCT Election for any Limited Condition Transaction, then in connection with any subsequent calculation of any ratio or basket availability with respect to any other Specified Transaction on or following the relevant LCT Test Date and prior to the earlier of the date on which such Limited Condition Transaction is consummated or the date that the definitive agreements for such Limited Condition Transaction are terminated or expire without consummation of such Limited Condition Transaction, any such ratio or basket shall be calculated on a *pro forma* basis assuming such Limited Condition Transaction and other Specified Transactions in connection therewith (including any incurrence of Indebtedness and the use of proceeds thereof) have been consummated until such time as the applicable Limited Condition Transaction has actually closed or the definitive agreements with respect thereto have been terminated or expire. Notwithstanding the foregoing, the Issuer may at any time withdraw any LCT Election, in which case any Indebtedness and Liens incurred in reliance on such LCT Election in accordance with the foregoing outstanding at such time, if any, shall be deemed to be incurred on the date of such withdrawal.

No Personal Liability of Directors, Officers, Employees, Managers and Shareholders

No director, officer, employee, manager, incorporator or holder of any Equity Interests in the Issuer or of any Guarantor, as such, will have any liability for any obligations of the Issuer or any Guarantor under the Notes, the indenture or the Guarantees, as applicable, or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder of Notes by accepting a note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the Notes. The waiver may not be effective to waive liabilities under the federal securities laws.

Transfer and Exchange

A noteholder may transfer or exchange Notes in accordance with the indenture. Upon any transfer or exchange, the registrar and the Trustee may require a noteholder, among other things, to furnish appropriate endorsements and transfer documents, and the Issuer may require a noteholder to pay any taxes required by law or permitted by the indenture. The Issuer is not required to transfer or exchange any Notes selected for redemption or to transfer or exchange any Notes for a period of 15 days prior to a selection of Notes to be redeemed or between a record date and the related interest payment date. The Notes will be issued in registered form and the registered holder of a note will be treated as the owner of such note for all purposes.

Satisfaction and Discharge

The indenture will be discharged and will cease to be of further effect (except as to surviving rights, indemnities and immunities of the Trustee and rights of transfer or exchange of Notes, as expressly provided for in the indenture) as to all outstanding Notes when:

(a) either (a) all the Notes theretofore authenticated and delivered (except lost, stolen or destroyed Notes that have been replaced or paid and Notes for whose payment money has theretofore been deposited in trust or segregated and held in trust by the Issuer and thereafter repaid to the Issuer or discharged from such trust) have been delivered to the Trustee for cancellation or (b) all the Notes (i) have become due and payable, (ii) will become due and payable at their Stated Maturity within one year or (iii) if redeemable at the option of the Issuer, are to be called for redemption within one year under arrangements satisfactory to the Trustee for the giving of notice of redemption by the Trustee in the name, and at the expense, of the Issuer, and the Issuer has irrevocably deposited or caused to be deposited with the Trustee funds in trust solely for the benefit of the holders in U.S. dollars in an amount sufficient to pay and discharge the entire Indebtedness on the Notes not theretofore delivered to the Trustee for cancellation, for principal of, premium, Additional Amounts, if any, and interest on the Notes to the date of deposit (in the case of Notes that have become due and payable) or to the date of maturity or redemption, as applicable, together with irrevocable written instructions from the Issuer directing the Trustee to apply such funds to the payment thereof at maturity or redemption, as the case may be; provided that upon any redemption that requires the payment of the Applicable Premium, the amount deposited shall be sufficient for purposes of the indenture to the extent that an amount is deposited with the Trustee equal to the Applicable Premium calculated as of the date of the notice of redemption, with any deficit as of the date of the redemption only required to be deposited with the Trustee on or prior to the date of the redemption;

(b) the Issuer and/or the Guarantors have paid all other sums payable under the indenture; and

(c) the Issuer has delivered to the Trustee an Officers' Certificate and an Opinion of Counsel stating that all conditions precedent under the indenture relating to the satisfaction and discharge of the indenture have been complied with.

Defeasance

Subject to the survival of certain terms and subject to certain conditions to defeasance, the Issuer at any time may at the option of its Board of Directors evidenced by a resolution set forth in an Officers' Certificate terminate all of its obligations under the Notes and the indenture with respect to the holders of such Notes ("legal defeasance"), except for certain obligations, including the rights of holders of outstanding Notes to receive payments in respect of the principal of or interest (including Additional Amounts) or premium on such Notes when such payments are due from the money for payments that is held in trust, those respecting the defeasance trust and obligations to register the transfer or exchange of such Notes, to issue temporary Notes and replace mutilated, destroyed, lost or stolen Notes and to maintain a registrar and paying agent in respect of such Notes and the rights, indemnities and immunities of the Trustee and the legal defeasance and covenant defeasance provisions of the indenture. The Issuer at any time may terminate its obligations under the covenants described under "—Certain Covenants" and the undertakings and covenants contained under "—Change of Control" and "—Certain Covenants—Merger, Amalgamation, Consolidation or Sale of All or Substantially All Assets" ("covenant defeasance"). If the Issuer exercises its legal defeasance option or its covenant defeasance option with respect to the Notes, each Guarantor will be released from all of its obligations with respect to its Guarantee of such Notes and the Security Documents.

The Issuer may exercise its legal defeasance option notwithstanding its prior exercise of the covenant defeasance option. If the Issuer exercises its legal defeasance option, payment of the Notes so defeased may not be accelerated because of an Event of Default with respect thereto. If the Issuer exercise its covenant defeasance option, payment of the Notes so defeased may not be accelerated because of an Event of Default specified in clause (d), (e), (g), (h) or (i) under "—Defaults" or because of the failure of the Parent Guarantor or Issuer to comply with clause (d) under "—Merger, Amalgamation, Consolidation or Sale of All or Substantially All Assets."

In order to exercise their defeasance option with respect to the Notes, the Issuer must irrevocably deposit in trust (the "defeasance trust") with the Trustee money or U.S. Government Obligations, or a combination of cash in U.S. dollars and U.S. Government Obligations, in amounts as will be sufficient in the opinion of a nationally recognized firm of independent public accountants, for the payment of principal, premium (if any) and interest (including Additional Amounts) on such Notes to redemption or maturity, as the case may be, must specify whether the Notes are being defeased to such stated date for payment or to a particular redemption date and must comply with certain other conditions, including delivery to the Trustee of an Opinion of Counsel to the effect that holders of such Notes will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such deposit and defeasance and will be subject to U.S. federal income tax on the same amount and in the same manner and at the same times as would have been the case if such deposit and defeasance had not occurred (and, in the case of legal defeasance only, such Opinion of Counsel must be based on a ruling of the Internal Revenue Service or change in applicable U.S. federal income tax law); provided that upon any redemption that requires the payment of the Applicable Premium, the amount deposited shall be sufficient for purposes of the indenture to the extent that an amount is deposited with the Trustee equal to the Applicable Premium calculated as of the date of the notice of redemption, with any deficit as of the date of the redemption only required to be deposited with the Trustee on or prior to the date of the redemption.

Concerning the Trustee

GLAS Trust Company LLC will be the Trustee under the indenture and has been appointed by the Issuer as registrar and a paying agent with regard to the Notes.

If the Trustee becomes a creditor of the Issuer or any Guarantor, the indenture limits the right of the Trustee to obtain payment of claims in certain cases, or to realize on certain property received in respect of any such claim as security or otherwise. The Trustee will be permitted to engage in other transactions; however, if it acquires any conflicting interest (as defined in the TIA), it must eliminate such conflict within 90 days, apply to the SEC for permission to continue as trustee (if the indenture has been qualified under the TIA) or resign.

Governing Law

The indenture will provide that it and the Notes will be governed by, and construed in accordance with, the laws of the State of New York.

Listing

The Issuer will apply to list the Notes on the SGX-ST and will use commercially reasonable efforts to obtain and maintain such listing; provided that if the admission of the Notes on the SGX-ST would, in the future, require the Issuer or the Parent Guarantor to publish financial information either more regularly than it would otherwise be required to or requires the Issuer or the Guarantors to publish separate financial information or if the listing, in the judgment of the Issuer, is unduly burdensome, the Issuer may seek an alternative admission to listing, trading and/or quotation for the Notes by another listing authority, stock exchange and/or quotation system. If such alternative admission to listing, trading and/or quotation of the Notes is not available to the Issuer or is, in the Issuer's commercially reasonable judgment, unduly burdensome, an alternative admission to listing, trading and/or quotation of the Notes may not be obtained.

So long as the Notes are listed on the SGX-ST and the rules of such exchange so require, transfers or exchange of definitive notes may be made by presenting and surrendering such Notes at and obtaining new definitive notes from the office of a Singapore paying agent to be appointed by the Issuer. The Notes will be traded in a minimum board lot size of S$200,000 (or its equivalent in foreign currencies) as long as the Notes are listed on the SGX-ST and the rules of the SGX-ST so require.

Certain Definitions

"A-IFRS" means Australian equivalents of the International Financial Reporting Standards as in effect on the date of the indenture.

"Acquired Indebtedness" means, with respect to any specified Person:

(a) Indebtedness of any other Person existing at the time such other Person is merged, consolidated or amalgamated with or into or became a Restricted Subsidiary of such specified Person; and

(b) Indebtedness secured by a Lien encumbering any asset acquired by such specified Person.

Acquired Indebtedness will be deemed to have been Incurred, with respect to clause (a) of the preceding sentence, on the date such Person becomes a Restricted Subsidiary and, with respect to clause (b) of the preceding sentence, on the date of consummation of such acquisition of such assets.

"Additional Refinancing Amount" means, in connection with the Incurrence of any Indebtedness, Disqualified Stock or Preferred Stock Incurred to refund, refinance or defease any existing Indebtedness, Disqualified Stock or Preferred Stock, the aggregate principal amount of additional Indebtedness, Disqualified Stock or Preferred Stock Incurred to pay interest, premiums or defeasance costs, in each case in an amount equal to the amount required by the instruments governing such existing Indebtedness (whether such existing Indebtedness is redeemed pursuant to a tender offer, optional redemption or otherwise), and fees and expenses Incurred in connection therewith.

"Additional Junior Class Debt" means, to the extent permitted by the then-existing Second Lien Documents, any additional indebtedness incurred by the Issuer and the Guarantors that is secured on an equal and ratable basis by the Liens securing the Second Lien Obligations on a pari passu basis.

"Additional Second Lien Documents" means, with respect to any Series of Additional Junior Class Debt, the Notes, indentures, credit agreements, collateral agreements, security documents, guarantees and other operative agreements evidencing or governing such Indebtedness and the Liens securing such Indebtedness, including the Additional Second Lien Security Documents and each other agreement entered into for the purpose of securing any series of Additional Junior Class Debt.

"Additional Second Lien Obligations" means, collectively, all amounts owing pursuant to any series of Additional Junior Class Debt designated as Additional Second Lien Obligations pursuant to the Second Lien Pari Passu Intercreditor Agreement on or after the Issue Date, including, without limitation, the obligation (including guarantee obligations) to pay principal, premium (if any), interest (including interest accruing after the commencement of any Insolvency Proceeding, regardless of whether or not allowed or allowable in such proceeding), penalties, fees, indemnifications, reimbursements, damages and other liabilities under any Additional Second Lien Document (including guarantees of the foregoing).

"Additional Second Lien Security Document" means any collateral agreement, security agreement or any other document now existing or entered into on or after the Issue Date that creates or purports to create Liens on any assets or properties of the Issuer or any Guarantor to secure any series of Additional Second Lien Obligations.

"Affiliate" of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For purposes of this definition, "control" (including, with correlative meanings, the terms "controlling," "controlled by" and "under common control with"), as used with respect to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such Person, whether through the ownership of voting securities, by agreement or otherwise.

"Applicable Premium" means the excess of (A) the present value of all remaining required interest payments through May 14, 2026 (excluding accrued and unpaid interest), plus the present value of the redemption price of the Notes being redeemed set forth under the caption "—Optional Redemption", assuming a redemption date of May 14, 2026, in each case computed by the Issuer using a discount rate equal to the Treasury Rate plus 50 basis points over (B) the then outstanding principal amount of the Notes being redeemed. For purposes of this definition, "Treasury Rate" means the rate per annum equal to the yield to maturity at the time of computation of the United States Treasury securities with a constant maturity as compiled and published in the most recent Federal Reserve Statistical Release H.15 (519) that has become publicly available at least two Business Days prior to such time (or, if such Statistical Release is no longer published, any publicly available source of similar market data) most nearly equal to the period from such date of prepayment to May 14, 2026; provided, however, that if the period from such date of prepayment to May 14, 2026 is not equal to the constant maturity of a United States Treasury security for which a weekly average yield is given, the Treasury Rate shall be obtained by linear interpolation (calculated to the nearest one-twelfth of a year) from the weekly average yields of United States Treasury securities for which such yields are given. The Trustee shall have no duty to verify the Issuer's calculation of the Applicable Premium and Treasury Rate.

"Asset Sale" means:

(a) the sale, conveyance, transfer, lease or other disposition (whether in a single transaction or a series of related transactions) of property or assets (including by way of Production Payments and Reserve Sales and Sale/Leaseback Transactions) (other than an operating lease entered into in the ordinary course of the Oil and Gas Business) (each referred to in this definition as a "disposition"); provided that the disposition of all or substantially or substantially all of the assets of the Parent Guarantor and the Restricted Subsidiaries taken as a whole will be governed by the provisions of the indenture described above under "—Change of Control" and/or the provisions described above under "—Merger, Amalgamation, Consolidation or Sale of All or Substantially All Assets" and not by the provisions of "—Certain Covenants—Asset Sales"; or

(b) the issuance or sale of Equity Interests (other than directors' qualifying shares and shares issued to foreign nationals or other third parties to the extent required by applicable law) of any Restricted Subsidiary (in each case other than to the Parent Guarantor or another Restricted Subsidiary) (whether in a single transaction or a series of related transactions), in each case other than:

(1) a disposition of cash, Cash Equivalents or Investment Grade Securities or obsolete, damaged or worn out property or equipment in the ordinary course of business;

(2) any Restricted Payment or Permitted Investment that is permitted to be made, and is made, under the covenant described under "—Certain Covenants—Limitation on Restricted Payments";

(3) any disposition of assets of the Parent Guarantor or any Restricted Subsidiary or issuance or sale of Equity Interests of any Restricted Subsidiary in any single transaction or series of related transactions, which assets or Equity Interests so disposed or issued have an aggregate Fair Market Value (as determined in good faith by the Issuer) of less than US$25.0 million;

(4) any disposition of property or assets, or the issuance of Equity Interests, by a Restricted Subsidiary to the Parent Guarantor or to another Restricted Subsidiary or by the Parent Guarantor to a Restricted Subsidiary;

(5) foreclosure or any similar action with respect to any property or other asset of any of the Restricted Subsidiaries;

(6) the disposition of inventory and other goods held for sale, including Hydrocarbons and other mineral products in the ordinary course of business;

(7) (a) dispositions of receivables in connection with the compromise, settlement or collection thereof in the ordinary course of business or in bankruptcy or similar proceedings and exclusive of factoring or similar arrangements; and (b) the disposition of accounts receivable pursuant to Permitted Invoice Discounting permitted by "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock;"

(8) any disposition of Capital Stock of a Restricted Subsidiary pursuant to an agreement or other obligation with or to a Person (other than a Restricted Subsidiary) from whom such Restricted Subsidiary was acquired or from whom such Restricted Subsidiary acquired its business and assets (having been newly formed in connection with such acquisition), made as part of such acquisition and in each case comprising all or a portion of the consideration in respect of such sale or acquisition;

(9) in the ordinary course of business, any trade or exchange by the Parent Guarantor or any Restricted Subsidiaries of oil and gas properties or other properties or assets for oil and gas properties or other properties or assets owned or held by another Person, provided that the Fair Market Value of the properties or assets traded or exchanged by the Parent Guarantor or such Restricted Subsidiary (together with any cash) is reasonably equivalent to the Fair Market Value of the properties or assets (together with any cash) to be received by the Parent Guarantor or such Restricted Subsidiary, and provided further that any net cash received must be applied in accordance with the provisions described above under "—Certain Covenants—Asset Sales;"

(10) the creation or perfection of a Permitted Lien and the exercise by any Person in whose favor a Permitted Lien is granted of any of its rights in respect of that Permitted Lien;

(11) any surrender, expiration or waiver of contract rights or the settlement, release, recovery on or surrender of contract, tort or other claims of any kind;

(12) any Production Payments and Reserve Sales; provided that any such Production Payments and Reserve Sales, other than incentive compensation programs on terms that are reasonably customary in the Oil and Gas Business for geologists, geophysicists and other providers of technical services to the Parent Guarantor or a Restricted Subsidiary, shall have been created, incurred, issued, assumed or guaranteed in connection with the acquisition or financing of, and within 60 days after the acquisition of, the property that is subject thereto;

(13) the abandonment, farm-out pursuant to a Farm-Out Agreement, lease or sublease of developed or undeveloped Oil and Gas Properties owned or held by the Parent Guarantor or any Restricted Subsidiary in the ordinary course of business and that are usual and customary in the Oil and Gas Business generally or in the geographic region in which such activities occur;

(14) a disposition (whether or not in the ordinary course of business) of any Oil and Gas Property or interest therein to which no proved or probable reserves are attributable at the time of such disposition; and

(15) licenses, leases and subleases of property (other than intellectual property) in the ordinary course of business and that does not materially interfere with the business of the Parent Guarantor, Issuer and any Restricted Subsidiaries taken as a whole;

provided that, notwithstanding anything above to the contrary, no Production Payment and Reserve Sale shall be deemed to not constitute an Asset Sale pursuant to clauses (1) through (15) above, other than pursuant to clauses (3) and (12) above.

"ASX" means the Australian Securities Exchange operated by ASX Limited, or any successor thereof.

"Authorized Officer" means as to any Person, the Chairman of the Board of Directors, the President, the Chief Executive Officer, the Chief Financial Officer, the Chief Operating Officer, any Executive Vice President, Senior Vice President or Vice President, the Treasurer, the Assistant or Vice Treasurer, the Vice President-Finance, the General Counsel, the Secretary, the Assistant Secretary and any manager, managing member or general partner, in each case, of such Person, and any other senior officer designated as such in writing to the Trustee by such Person. Any document delivered under the indenture that is signed by an Authorized Officer shall be conclusively presumed to have been authorized by all necessary corporate, limited liability company, partnership and/or other action on the part of the Issuer or any Guarantor and such Authorized Officer shall be conclusively presumed to have acted on behalf of such Person.

"Bank Indebtedness" means any and all amounts payable under or in respect of (a) the RBL facility and the other RBL Facility Documents, as amended, restated, supplemented, waived, replaced (whether or not upon termination, and whether with the original lenders or otherwise), repaid, refunded, refinanced or otherwise modified from time to time (including after termination of the RBL facility), including any agreement extending the maturity thereof, refinancing or replacing all or any portion of the Indebtedness under such agreement or agreements or any successor or replacement agreement or agreements or increasing the amount loaned or issued thereunder or altering the maturity thereof, including principal, premium (if any), interest (including interest accruing on or after the filing of any petition in bankruptcy or for reorganization relating to the Parent Guarantor whether or not a claim for post-filing interest is allowed in such proceedings), fees, charges, expenses, reimbursement obligations, guarantees and all other amounts payable thereunder or in respect thereof and (b) whether or not the Indebtedness referred to in clause (a) remains outstanding, if designated by the Issuer to be included in this definition or incurred pursuant to clause (a) of the second paragraph of the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock, one or more (A) debt facilities or commercial paper facilities, providing for revolving credit loans, term loans, reserve based loans, or letters of credit, (B) debt securities, indentures or other forms of debt financing (including convertible or exchangeable debt instruments or bank guarantees or bankers' acceptances), or (C) instruments or agreements evidencing any other Indebtedness, in each case, with the same or different borrowers or issuers and, in each case, as amended, supplemented, modified, extended, restructured, renewed, refinanced, restated, replaced or refunded in whole or in part from time to time.

"Bankruptcy Code" means Title 11 of the United States Code, as now and hereafter in effect, or any successor statute.

"Bankruptcy Law" means the Bankruptcy Code or any similar federal, state or foreign bankruptcy, insolvency or receivership law for the relief of debtors.

"Beneficial Owner" has the meaning assigned to such term in Rule 13d-3 and Rule 13d-5 under the Exchange Act, except that in calculating the beneficial ownership of any particular "person" (as that term is used in Section 13(d)(3) of the Exchange Act), such "person" will be deemed to have beneficial ownership of all securities that such "person" has the right to acquire by conversion or exercise of other securities, whether such right is currently exercisable or is exercisable only after the passage of time. The terms "Beneficially Owns" and "Beneficially Owned" have a corresponding meaning. For purposes of this definition, a Person shall be deemed not to Beneficially Own securities that are the subject of a stock purchase agreement, merger agreement, amalgamation agreement, arrangement agreement or similar agreement until consummation of the transactions or, as applicable, series of related transactions contemplated thereby.

"Board of Directors" means, as to any Person, the board of directors or managers, as applicable, of such Person (or, if such Person is a partnership, the board of directors or other governing body of the general partner of such Person) or any duly authorized committee thereof. In the case of the Issuer, the Board of Directors of the Issuer shall be deemed to include the Board of Directors of the Issuer or any direct or indirect parent of the Issuer (including the Parent Guarantor), as appropriate.

"Borrowing Base Obligors" means KEI (Brazil Santos), KEI Finance and KPG and each other Subsidiary designated as such (or designated as any similar or corresponding term) in respect of the RBL facility or Senior Lien Intercreditor Documents.

"Business Day" means a day other than a Saturday, Sunday or other day on which banking institutions are authorized or required by law to close in New York City and Sydney.

"Calculation Date" means with respect to the Fixed Charge Coverage Ratio and the Gross Secured Leverage Ratio the date of the event for which the calculation of such ratio is made.

"Capital Stock" means:

(a) in the case of a corporation, corporate stock or shares;

(b) in the case of an association or business entity, any and all shares, interests, participations, rights or other equivalents (however designated) of corporate stock;

(c) in the case of a partnership or limited liability company, partnership or membership interests (whether general or limited); and

(d) any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distributions of assets of, the issuing Person.

"Cash Equivalents" means:

(a) U.S. dollars, Australian dollars, pounds sterling, euros, the national currency of any member state in the European Union, Brazilian Real or such local currencies held by an entity from time to time in the ordinary course of business;

(b) securities issued or directly and fully guaranteed or insured by the Australian government, the U.S. government or any country that is a member of the European Union or any agency or instrumentality thereof in each case maturing not more than two years from the date of acquisition;

(c) certificates of deposit, time deposits and eurodollar time deposits with maturities of one year or less from the date of acquisition, bankers' acceptances, in each case with maturities not exceeding one year and overnight bank deposits, in each case with any commercial bank having capital and surplus in excess of US$250.0 million and whose credit rating from Moody's, Fitch or S&P (or reasonably equivalent ratings of another internationally or nationally recognized ratings agency) is equal to or greater than the lower of (x) an Investment Grade Rating or (y) the credit rating of such jurisdiction in which the Issuer or any Guarantor is incorporated or organized or the borrowing base assets of the Borrowing Base Obligors are located;

(d) repurchase obligations with a term of not more than seven days for underlying securities of the types described in clauses (b) and (c) above entered into with any financial institution meeting the qualifications specified in clause (c) above;

(e) commercial paper issued by a corporation (other than an Affiliate of the Issuer) rated at least one of the two highest Rating Categories obtainable by Moody's, Fitch or S&P (or reasonably equivalent ratings of another internationally recognized ratings agency) and in each case maturing within one year after the date of acquisition;

(f) readily marketable direct obligations issued by any state of Australia or the United States of America or any political subdivision thereof having one of the two highest Rating Categories obtainable from either Moody's, Fitch or S&P (or reasonably equivalent ratings of another internationally recognized ratings agency) in each case with maturities not exceeding two years from the date of acquisition; and

(g) investment funds investing at least 95% of their assets in securities of the types described in clauses (a) through (f) above.

"Change of Control" means the occurrence of any of the following:

(a) the direct or indirect sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the properties or assets of the Parent Guarantor and its Subsidiaries taken as a whole to any Person other than a Restricted Subsidiary of the Parent Guarantor (including any "person" (as that term is used in Section 13(d)(3) of the Exchange Act));

(b) the Parent Guarantor ceases to directly or indirectly hold 100% of the Equity Interests of the Issuer;

(c) the adoption of a plan relating to the liquidation or dissolution of the Parent Guarantor or the Issuer; or

(d) the consummation of any transaction (including any merger or consolidation), the result of which is that any Person (including any "person" as defined above) becomes the Beneficial Owner, directly or indirectly, of more than 50% of the Voting Stock of the Parent Guarantor, measured by voting power rather than number of shares;

and, in the case of clauses (a) and (d) above, a Rating Decline occurs during the period between the announcement of the impending Change of Control and the date that is 60 days after the earlier of (1) the date a Change of Control occurs, or (2) the date of public notice of the occurrence of (x) a Change of Control or (y) the intention by the Issuer or any other Person or Persons to effect a Change of Control, which period shall be extended with respect to a Rating Agency for a period not longer than 60 days so long as the rating of the Notes is under publicly announced consideration for downgrade by the applicable Rating Agency relating to the Change of Control.

Notwithstanding the preceding or any provision of Section 13(d)(3) of the Exchange Act, (i) a Person or group shall not be deemed to beneficially own Voting Stock subject to a stock or asset purchase agreement, merger agreement, option agreement, warrant agreement or similar agreement (or voting or option or similar agreement related thereto) until the consummation of the acquisition of the Voting Stock in connection with the transactions contemplated by such agreement, (ii) a Person or group will not be deemed to beneficially own the Voting Stock of another Person as a result of its ownership of Voting Stock or other securities of such other Person's parent entity (or related contractual rights) unless it owns 50% or more of the total voting power of the Voting Stock entitled to vote for the election of directors of such parent entity having a majority of the aggregate votes on the Board of Directors (or similar body) of such parent entity, and (iii) the right to acquire Voting Stock (so long as such Person does not have the right to direct the voting of the Voting Stock subject to such right) or any veto power in connection with the acquisition or disposition of Voting Stock will not cause a party to be a beneficial owner.

"Code" means the Internal Revenue Code of 1986, as amended.

"Collateral" means all property subject or purported to be subject, from time to time, to a Lien under any Security Documents.

"Common Security Agent" means Citibank, N.A., London Branch as offshore security agent and Banco Citibank S.A. as onshore security agent under the Senior Lien Intercreditor Documents and any successor thereto in such capacity.

"Consolidated Interest Expense" means, with respect to any Person for any period, the sum, without duplication, of:

(a) consolidated interest expense of such Person and its Restricted Subsidiaries for such period, to the extent such expense was deducted in computing Consolidated Net Income (including amortization of original issue discount, the interest component of Financing Lease Obligations, and net payments and receipts (if any) pursuant to interest rate Hedging Obligations and excluding amortization of deferred financing fees, any interest attributable to Dollar Denominated Production Payments, debt issuance costs, commissions, fees and expenses, expensing of any bridge, commitment or other financing fees and non-cash interest expense attributable to movement in mark to market valuation of Hedging Obligations or other derivatives (in each case permitted hereunder) under A-IFRS); *plus*

(b) consolidated capitalized interest of such Person and its Restricted Subsidiaries for such period, whether paid or accrued; *minus*

(c) interest income for such period.

For purposes of this definition, interest on a Financing Lease Obligation shall be deemed to accrue at an interest rate reasonably determined by the Issuer to be the rate of interest implicit in such Financing Lease Obligation in accordance with A-IFRS.

"Consolidated Net Income" means, with respect to any Person for any period, the aggregate of the Net Income of such Person and its Restricted Subsidiaries for such period, on a consolidated basis; provided, however, that, without duplication:

(a) any (i) net after-tax extraordinary or nonrecurring gains or losses (less all fees and expenses relating thereto) or expenses or charges, (ii) any severance expenses, acquisition integration costs, expenses or charges related to any issuance of Equity Interests, Investment, acquisition, disposition, recapitalization or issuance, repayment, refinancing, amendment or modification of Indebtedness (in each case, whether or not successful) and (iii) hurricane costs and charges, shall be excluded; provided that the aggregate amount of non-cash items excluded and resulting in an increase to Consolidated Net Income pursuant to this clause (a) plus the aggregate amount of operating expense reductions and other operating improvements or synergies added to EBITDAX pursuant to the second paragraph of the definition of Fixed Charge Coverage Ratio or pursuant to the second paragraph of the definition of Gross Secured Leverage Ratio shall not exceed, in any two consecutive semi-annual reporting periods, an amount equivalent to 20% of EBITDAX for the applicable two consecutive semi-annual reporting periods, prior to giving effect to such exclusions, add-backs or other adjustments;

(b) effects of purchase accounting adjustments (including the effects of such adjustments pushed down to such Person and such Subsidiaries) in amounts required or permitted by A-IFRS, resulting from the application of purchase accounting or the amortization or write-off of any amounts thereof, net of taxes, shall be excluded;

(c) the Net Income for such period shall not include the cumulative effect of a change in accounting principles during such period;

(d) any net after-tax income or loss (less all fees and expenses or charges relating thereto) from disposed, abandoned, transferred, closed or discontinued operations or fixed assets and any net after-tax gains or losses on disposal of disposed, abandoned, transferred, closed or discontinued operations or fixed assets or attributable to business dispositions or other asset dispositions other than in the ordinary course of business (as determined in good faith by management of the Parent Guarantor) shall be excluded;

(e) any net after-tax gains or losses (less all fees and expenses or charges relating thereto) attributable to the early extinguishment of indebtedness, Hedging Obligations or other derivative instruments shall be excluded;

(f) the Net Income for such period of any Person that is not a Subsidiary of such Person, or is an Unrestricted Subsidiary, or that is accounted for by the equity method of accounting, shall be included only to the extent of the amount of dividends or distributions or other payments paid in cash (or to the extent converted into cash) to the referent Person or a Restricted Subsidiary thereof in respect of such period;

(g) solely for the purpose of determining the amount available for Restricted Payments under clause (i) of the definition of Cumulative Credit contained in "—Certain Covenants—Limitation on Restricted Payments," the Net Income for such period of any Restricted Subsidiary (other than any Subsidiary Guarantor) shall be excluded to the extent that the declaration or payment of dividends or similar distributions by such Restricted Subsidiary of its Net Income is not at the date of determination permitted without any prior governmental approval (which has not been obtained) or, directly or indirectly, by the operation of the terms of its charter or any agreement, instrument, judgment, decree, order, statute, rule or governmental regulation applicable to that Restricted Subsidiary or its shareholders, unless such restrictions with respect to the payment of dividends or similar distributions have been legally waived; provided that the Consolidated Net Income of such Person shall be increased by the amount of dividends or other distributions or other payments actually paid in cash (or converted into cash) by any such Restricted Subsidiary to such Person, to the extent not already included therein;

(h) (i) any impairment charges or asset write-offs, in each case pursuant to A-IFRS, (ii) the amortization of intangibles arising pursuant to A-IFRS, and (iii) any impairment charges, asset write-offs or write-down, including ceiling test write downs, on Oil and Gas Properties under A-IFRS or SEC guidelines shall be excluded;

(i) any non-cash expense realized or resulting from stock option plans, employee benefit plans or post-employment benefit plans, or grants or sales of stock, stock appreciation or similar rights, stock options, restricted stock, preferred stock or other rights shall be excluded;

(j) any currency translation gains and losses related to currency remeasurements of Indebtedness, and any net loss or gain resulting from hedging transactions for currency exchange risk, shall be excluded; and

(k) (i) to the extent covered by insurance and actually reimbursed, or, so long as such Person has made a determination that there exists reasonable evidence that such amount will in fact be reimbursed by the insurer and only to the extent that such amount is (x) not denied by the applicable carrier in writing within 180 days and (y) in fact reimbursed within 365 days of the date of such evidence (with a deduction for any amount so added back to the extent not so reimbursed within 365 days), expenses with respect to liability or casualty events or business interruption shall be excluded and (ii) amounts estimated in good faith to be received from insurance in respect of lost revenues or earnings in respect of liability or casualty events or business interruption shall be included (with a deduction for amounts actually received up to such estimated amount to the extent included in Net Income in a future period less a deduction for any amounts so added back to the extent not so received within 365 days).

Notwithstanding the foregoing, for the purpose of the covenant described under "—Certain Covenants—Limitation on Restricted Payments" only, there shall be excluded from Consolidated Net Income any dividends, repayments of loans or advances or other transfers of assets from Unrestricted Subsidiaries or Restricted Subsidiaries to the extent such dividends, repayments or transfers increase the amount of Restricted Payments permitted under such covenant pursuant to clauses (iv), (v), (vi) and (vii) of the definition of Cumulative Credit contained therein.

"Consolidated Total Indebtedness" means, as of any date of determination, an amount equal to the sum (without duplication) of (1) the aggregate principal amount of all outstanding Indebtedness of the Parent Guarantor and the Restricted Subsidiaries (excluding any undrawn letters of credit) consisting of Financing Lease Obligations, bankers' acceptances and Indebtedness for borrowed money, plus (2) the aggregate amount of all outstanding Disqualified Stock of the Parent Guarantor and the Restricted Subsidiaries and all Preferred Stock of Restricted Subsidiaries, with the amount of such Disqualified Stock and Preferred Stock equal to the greater of their respective voluntary or involuntary liquidation preferences, in each case determined on a consolidated basis in accordance with A-IFRS.

"Contingent Obligations" means, with respect to any Person, any obligation of such Person guaranteeing any leases, dividends or other obligations that do not constitute Indebtedness ("primary obligations") of any other Person (the "primary obligor") in any manner, whether directly or indirectly, including, without limitation, any obligation of such Person, whether or not contingent:

(a) to purchase any such primary obligation or any property constituting direct or indirect security therefor,

(b) to advance or supply funds:

  (i) for the purchase or payment of any such primary obligation; or

  (ii) to maintain working capital or equity capital of the primary obligor or otherwise to maintain the net worth or solvency of the primary obligor; or

(c) to purchase property, securities or services primarily for the purpose of assuring the owner of any such primary obligation of the ability of the primary obligor to make payment of such primary obligation against loss in respect thereof.

"Corporate Debtor" means the Parent Guarantor, KEI, New Aus SPV, KUSA Inc. and the Issuer and each other Subsidiary designated as such (or designated as any similar or corresponding term) in respect of the RBL facility or Senior Lien Intercreditor Documents.

"Corporate Trust Office" means the designated office of the Trustee in the United States of America at which at any time its corporate trust business shall be administered, or such other address as the Trustee may designate from time to time by notice to the holders and the Issuer, or the principal corporate trust office of any successor Trustee (or such other address as such successor Trustee may designate from time to time by notice to the holders and the Issuer).

"Credit Facilities" means one or more debt facilities (including the RBL facility) or other credit agreements, indentures, commercial paper facilities or other arrangements with banks, investment banks, insurance companies, trust companies, mutual funds or other lenders providing for revolving credit loans, term loans, capital market financings, debt securities, receivables financing (including through the sale of receivables to such lenders or to special purpose entities formed to borrow from such lenders against such receivables), letters of credit or other Indebtedness, in each case, as amended, restated, modified, renewed, refunded, replaced in any manner (whether upon or after termination or otherwise) or refinanced (including by means of sales of debt securities) in whole or in part from time to time.

"Customary Intercreditor Agreement" means (a) in connection with the incurrence of Pari Passu Indebtedness that is to be secured by Liens on the Collateral securing such Pari Passu Indebtedness that shall rank equal in priority to the Liens on the Collateral securing the Notes Obligations, an intercreditor agreement among the Trustee, a collateral agent (as applicable) and one or more agents for holders of such Pari Passu Indebtedness in the form delivered by the Issuer to the Trustee and a collateral agent (as applicable) providing that, inter alia, the Liens on the Collateral in favor or for the benefit of a collateral agent (as applicable) shall be pari passu to such Liens in favor of such agent for holders of Pari Passu Indebtedness; provided that such intercreditor agreement shall provide that the largest series of Pari Passu Indebtedness by outstanding principal amount at the time of such agreement is entered into shall control the enforcement of rights and remedies with respect to the Collateral and such intercreditor agreement shall otherwise contain customary terms consistent with then prevailing market terms as determined in good faith by the Issuer (and, to the extent necessary by the terms thereof, a joinder to the Senior Lien Intercreditor Documents shall be executed with respect to such Pari Passu Indebtedness) and (b) to the extent executed in connection with the incurrence of Indebtedness secured by junior Liens, an intercreditor agreement substantially in the form of the Senior Lien Intercreditor Documents where the Notes Obligations shall be the senior obligations thereunder (with such modifications as may be necessary or appropriate in light of prevailing market conditions and are not materially adverse to the holders of Notes, taken as a whole). It is acknowledged and agreed that the Second Lien Pari Passu Intercreditor Agreement constitutes a Customary Intercreditor Agreement.

"Customary Recourse Exceptions" means, with respect to any Non-Recourse Debt of an Unrestricted Subsidiary, exclusions from the exculpation provisions with respect to such Non-Recourse Debt for the voluntary bankruptcy of such Unrestricted Subsidiary, fraud, misapplication of cash, environmental claims, waste, willful destruction and other circumstances customarily excluded by lenders from exculpation provisions or included in separate indemnification agreements in non-recourse financings.

"Debtors" means the Borrowing Base Obligors and the Corporate Debtors.

"Default" means any event that is, or after notice or passage of time or both would be, an Event of Default.

"Designated Non-cash Consideration" means the Fair Market Value (as determined in good faith by the Issuer) of non-cash consideration received by the Issuer or a Guarantor in connection with an Asset Sale that is so designated as Designated Non-cash Consideration pursuant to an Officers' Certificate, setting forth the basis of such valuation, less the amount of Cash Equivalents received in connection with a subsequent sale of such Designated Non-cash Consideration; provided that if the assets disposed of in the applicable Asset Sale constitute Collateral, the assets designated as Designated Non-cash Consideration must constitute Collateral as of the date of receipt thereof.

"Designated Preferred Stock" means Preferred Stock of the Parent Guarantor (other than Disqualified Stock), that is issued for cash (other than to the Parent Guarantor or any of its Subsidiaries or an employee stock ownership plan or trust established by the Parent Guarantor or any of its Subsidiaries) and is so designated as Designated Preferred Stock, pursuant to an Officers' Certificate, on the issuance date thereof.

"Discharge of First Priority Lien Obligations" means, except to the extent otherwise provided in the Senior Lien Intercreditor Documents, with respect to any First Priority Lien Obligations, (a) payment in full in immediately available funds of the principal of, and interest (including interest accruing on or after the commencement of an Insolvency Proceeding, whether or not such interest would be allowed in the proceeding) accrued on, all outstanding Indebtedness included in such First Priority Lien Obligations after or concurrently with the termination of all commitments to extend credit thereunder (other than, if applicable, pursuant to cash management agreements or Hedging Obligations secured by such First Priority Lien Obligations, in each case as provided under the relevant document evidencing such First Priority Lien Obligation or as to which reasonably satisfactory arrangements have been made with the relevant bank providing such cash management or hedging agreements pursuant to which such Hedging Obligations have been incurred), (b) with respect to any letters of credit or letters of credit guaranties that may be outstanding in respect of any First Priority Lien Obligations, termination or delivery of cash collateral, backstop letters of credit or other credit support in respect thereof in an amount and manner in compliance with the relevant document evidencing such First Priority Lien Obligation, and (c) payment in full in immediately available funds of any other First Priority Lien Obligations that are due and payable or otherwise accrued and owing at or prior to the time such principal and interest are paid (other than in respect of contingent indemnification and expense reimbursement claims not then due); provided that the Discharge of First Priority Lien Obligations shall not be deemed to have occurred if such payments are made with the proceeds other First Priority Lien Obligations that constitute an exchange or replacement for or a refinancing of such First Priority Lien Obligations.

"Disqualified Stock" means, with respect to any Person, any Capital Stock of such Person that, by its terms (or by the terms of any security into which it is convertible or for which it is redeemable or exchangeable), or upon the happening of any event:

(a) matures or is mandatorily redeemable, pursuant to a sinking fund obligation or otherwise (other than as a result of a change of control or asset sale),

(b) is convertible or exchangeable for Indebtedness or Disqualified Stock of such Person, or

(c) is redeemable at the option of the holder thereof, in whole or in part (other than solely as a result of a change of control or asset sale),

in each case prior to 91 days after the earlier of the maturity date of the Notes or the date such Notes are no longer outstanding; provided, however, that only the portion of Capital Stock that so matures or is mandatorily redeemable, is so convertible or exchangeable or is so redeemable at the option of the holder thereof prior to such date shall be deemed to be Disqualified Stock; provided, further, however, that if such Capital Stock is issued to any employee or to any plan for the benefit of employees of the Parent Guarantor or its Subsidiaries or by any such plan to such employees, such Capital Stock shall not constitute Disqualified Stock solely because it may be required to be repurchased by such Person in order to satisfy applicable statutory or regulatory obligations or as a result of such employee's termination, death or disability; provided, further, that any class of Capital Stock of such Person that by its terms authorizes such Person to satisfy its obligations thereunder by delivery of Capital Stock that is not Disqualified Stock shall not be deemed to be Disqualified Stock.

"Dollar Denominated Production Payments" means production payment obligations recorded as liabilities in accordance with A-IFRS, together with all undertakings and obligations in connection therewith.

"EBITDAX" means, with respect to any Person for any period, the Consolidated Net Income of such Person and its Restricted Subsidiaries for such period plus, without duplication, to the extent the same was deducted in calculating Consolidated Net Income:

(a) taxes based on income or profits of such Person and its Restricted Subsidiaries for such period to the extent deducted in calculating such Consolidated Net Income; *plus*

(b) the Fixed Charges of such Person and its Restricted Subsidiaries for such period to the extent deducted in calculating such Consolidated Net Income; *plus*

(c) depreciation, depletion, amortization (including, without limitation, amortization of intangibles and deferred financing fees but excluding amortization of prepaid cash expenses that were paid in a prior period), impairment and other non-cash charges and expenses (including, without limitation, write downs and impairment of property, plant, equipment and intangible and other long lived assets and the impact of purchase accounting on such Person and its Restricted Subsidiaries for such period), of such Person and its Restricted Subsidiaries (excluding any such non-cash expense to the extent that it represents an accrual of or reserve for cash expenses in any future period or amortization of a prepaid cash expense that was paid in a prior period) for such period to the extent deducted in calculating such Consolidated Net Income; *plus*

(d) any expenses, charges or other costs related to the issuance of any Capital Stock, or any Permitted Investment, acquisition, disposition, recapitalization or listing or the incurrence of Indebtedness permitted to be incurred under the covenant described above under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" (including any permitted refinancing thereof) whether or not successful, including (i) such fees, expenses or charges related to any incurrence of Indebtedness issuance and (ii) any amendment or other modification of any incurrence, in each case to the extent deducted in calculating such Consolidated Net Income; *plus*

(e) any non-cash foreign currency translation losses (including losses related to currency remeasurements of Indebtedness); *plus*

(f) the amount of any minority interest expense (whether paid or not) consisting of subsidiary income attributable to minority interests of third parties in any non-wholly owned Restricted Subsidiary in such period or any prior period, except to the extent of dividends declared or paid on, or other cash payments in respect of, Equity Interests held by such parties; *plus*

(g) if such Person accounts for its oil and natural gas operations using successful efforts or a similar method of accounting, consolidated exploration and abandonment expense and write-offs of such Person and its Restricted Subsidiaries; *plus*

(h) any income or charge attributable to a post-employment benefit scheme other than the current service costs and any past service costs and curtailments and settlements attributable to the scheme; *plus*

(i) the proceeds of any business interruption insurance received or that become receivable during such period to the extent the associated losses arising out of the event that resulted in the payment of such business interruption insurance proceeds were included in computing Consolidated Net Income; *plus*

(j) payments received or that become receivable with respect to expenses that are covered by the indemnification provisions in any agreement entered into by such Person in connection with an acquisition to the extent such expenses were included in computing Consolidated Net Income; *minus*

(k) non-cash items increasing such Consolidated Net Income for such period (other than any non-cash items increasing such Consolidated Net Income pursuant to clauses (a), (c), (h) and (j) of the definition of Consolidated Net Income), other than items that were accrued in the ordinary course of business; and *minus*

(l) the sum of (i) the amount of deferred revenues that are amortized during such period and are attributable to reserves that are subject to Volumetric Production Payments and (ii) amounts recorded in accordance with A-IFRS as repayments of principal and interest pursuant to Dollar Denominated Production Payments.

"Equity Interests" means Capital Stock and all warrants, options or other rights to acquire Capital Stock (but excluding any debt security that is convertible into, or exchangeable for, Capital Stock).

"Equity Offering" means any public or private sale after the Issue Date of common Capital Stock or Preferred Stock of the Parent Guarantor or any of its Subsidiaries (other than Disqualified Stock), other than (1) issuances for non-cash proceeds, (2) issuances pursuant to an employee compensation plan or (3) the issuances to any Subsidiary of the Parent Guarantor.

"Exchange Act" means the Securities Exchange Act of 1934, as amended, and the rules and regulations of the SEC promulgated thereunder.

"Fair Market Value" means, with respect to any asset or property, the price that could be negotiated in an arm's length transaction not involving distress or necessity of either party, for cash, between a willing seller and a willing and able buyer, neither of whom is under undue pressure or compulsion to complete the transaction.

"Farm-In Agreement" means an agreement whereby a Person agrees to pay all or a share of the drilling, completion or other expenses of one or more exploratory or development wells (which agreement may be subject to a maximum payment obligation, after which expenses are shared in accordance with the working or participation interests therein or in accordance with the agreement of the parties) or perform the drilling, completion or other operation on such well or wells as all or a part of the consideration provided in exchange for an ownership interest in an Oil and Gas Property.

"Farm-Out Agreement" means a Farm-In Agreement, viewed from the standpoint of the party that transfers an ownership interest to another.

"Financing Lease Obligation" means, at the time any determination thereof is to be made, the amount of the liability in respect of a financing lease that would at such time be required to be capitalized and reflected as a liability on a balance sheet (excluding the footnotes thereto) in accordance with A-IFRS (other than a lease or hire purchase contract that would in accordance with A-IFRS in force prior to January 1, 2019 have been treated as an operating lease).

"First Priority After-Acquired Property" means any property of the Issuer or any Guarantor that secures any Secured Bank Indebtedness that is not already subject to the Lien under the Security Documents, including, for the avoidance of doubt, any property of the Issuer or any Guarantor that secures any Secured Bank Indebtedness on the Issue Date.

"First Priority Lien Obligations" means (i) all Secured Bank Indebtedness that is secured by the Collateral on a senior basis to the Liens securing the Notes Obligations and (ii) all other obligations of the Parent Guarantor or any of its Restricted Subsidiaries in respect of Hedging Obligations or obligations in respect of cash management services that are secured by the Collateral on a senior basis to the Liens securing the Notes Obligations, in each case owing to a Person that is a holder of Secured Bank Indebtedness or an Affiliate of such holder at the time of entry into such Hedging Obligations or obligations in respect of cash management services.

"First priority Secured Parties" means the persons holding any First Priority Lien Obligations.

"Fitch" means Fitch Ratings, Inc. or any successor to the rating agency business thereof.

"Fixed Charge Coverage Ratio" means, with respect to any Person for any period, the ratio of EBITDAX of such Person for such period to the Fixed Charges of such Person for such period. In the event that the Parent Guarantor or any Restricted Subsidiary Incurs, repays, repurchases or redeems any Indebtedness or issues, repurchases or redeems Disqualified Stock or Preferred Stock subsequent to the commencement of the period for which the Fixed Charge Coverage Ratio is being calculated but prior to the relevant Calculation Date, then the Fixed Charge Coverage Ratio shall be calculated giving *pro forma* effect to such Incurrence, repayment, repurchase or redemption of Indebtedness, or such issuance, repurchase or redemption of Disqualified Stock or Preferred Stock, as if the same had occurred at the beginning of the applicable two full fiscal semi-annual periods; provided that the Issuer may elect pursuant to an Officers' Certificate delivered to the Trustee to treat all or any portion of the commitment under any Indebtedness as being Incurred at such time, in which case any subsequent Incurrence of Indebtedness under such commitment shall not be deemed, for purposes of this calculation, to be an Incurrence at such subsequent time.

For purposes of making the computation referred to above, Investments, acquisitions, dispositions, mergers, amalgamations, consolidations and discontinued operations (as determined in accordance with A-IFRS), in each case with respect to an operating unit of a business, and any operational changes that the Parent Guarantor or any Restricted Subsidiary has determined to make and/or made during or subsequent to such reference period and on or prior to or simultaneously with the Calculation Date shall be calculated on a *pro forma* basis assuming that all such Investments, acquisitions, dispositions, mergers, amalgamations, consolidations, discontinued operations and other operational changes (and the change of any associated fixed charge obligations and the change in EBITDAX resulting therefrom) had occurred on the first day of the two full fiscal semi-annual reference periods. If since the beginning of such period any Person that subsequently became a Restricted Subsidiary or was merged with or into the Parent Guarantor or any Restricted Subsidiary since the beginning of such period shall have made any Investment, acquisition, disposition, merger, consolidation, amalgamation, discontinued operation or operational change, in each case with respect to an operating unit of a business, that would have required adjustment pursuant to this definition, then the Fixed Charge Coverage Ratio shall be calculated giving *pro forma* effect thereto for such period as if such Investment, acquisition, disposition, discontinued operation, merger, amalgamation, consolidation or operational change had occurred at the beginning of the applicable two full fiscal semi-annual periods. If since the beginning of such period any Restricted Subsidiary is designated an Unrestricted Subsidiary or any Unrestricted Subsidiary is designated a Restricted Subsidiary, then the Fixed Charge Coverage Ratio shall be calculated giving *pro forma* effect thereto for such period as if such designation had occurred at the beginning of the applicable two full fiscal semi-annual periods.

For purposes of this definition, whenever *pro forma* effect is to be given to any event, the *pro forma* calculations shall be made in good faith by a responsible financial or accounting officer of the Issuer. Any such *pro forma* calculation may include adjustments appropriate, in the reasonable good faith determination of the Issuer as set forth in an Officers' Certificate, to reflect operating expense reductions and other operating improvements or synergies reasonably expected to result from the applicable event on or prior to the date that is 12 months after such applicable event; provided that the aggregate amount of operating expense reductions and other operating improvements or synergies added to EBITDAX pursuant to the preceding paragraph, the second paragraph of the definition of Gross Secured Leverage Ratio or the second paragraph of the definition of Net Leverage Ratio plus the aggregate amount of non-cash items excluded and resulting in an increase to Consolidated Net Income pursuant to clause (a) of the definition thereof shall not exceed, in any two consecutive semi-annual reporting periods, an amount equivalent to 20% of EBITDAX for the applicable two consecutive semi-annual reporting periods, prior to giving effect to such exclusions, add-backs or other adjustments.

If any Indebtedness bears a floating rate of interest and is being given *pro forma* effect, the interest on such Indebtedness shall be calculated as if the rate in effect on the Calculation Date had been the applicable rate for the entire period (taking into account any Hedging Obligations applicable to such Indebtedness if such Hedging Obligation has a remaining term in excess of 12 months). Interest on a Financing Lease Obligation shall be deemed to accrue at an interest rate reasonably determined by a responsible financial or accounting officer of the Issuer to be the rate of interest implicit in such Financing Lease Obligation in accordance with A-IFRS. For purposes of making the computation referred to above, interest on any Indebtedness under a revolving credit facility computed on a *pro forma* basis shall be computed based upon the average daily balance of such Indebtedness during the applicable period. Interest on Indebtedness that may optionally be determined at an interest rate based upon a factor of a prime or similar rate, a Eurocurrency interbank offered rate, or other rate, shall be deemed to have been based upon the rate actually chosen, or, if none, then based upon such optional rate chosen as the Issuer may designate.

For purposes of this definition, any amount in a currency other than U.S. dollars will be converted to U.S. dollars based on the average exchange rate for such currency for the most recent 12-month period immediately prior to the date of determination in a manner consistent with that used in calculating EBITDAX for the applicable period.

"Fixed Charges" means, with respect to any Person for any period, the sum, without duplication, of: (1) Consolidated Interest Expense (excluding amortization or write-off of deferred financing costs) of such Person for such period, and (2) all cash dividend payments (excluding items eliminated in consolidation) on any series of Preferred Stock or Disqualified Stock of such Person and its Restricted Subsidiaries.

"FPSO" means any floating storage and offloading unit, floating storage and production unit, floating production, storage and offloading unit or similar moveable infrastructure (including vessels used or useful in connection with performing seismic surveys) and any related infrastructure in connection with the foregoing.

"Gross Secured Leverage Ratio" means, with respect to any date of determination, the ratio of (1) Secured Indebtedness outstanding as of the last day of the then applicable two full fiscal semi-annual periods to (2) EBITDAX for such two full fiscal semi-annual periods. In the event that the Parent Guarantor or any Restricted Subsidiary Incurs, repays, repurchases or redeems any Indebtedness or issues, repurchases or redeems Disqualified Stock or Preferred Stock subsequent to the commencement of the period for which the Gross Secured Leverage Ratio is being calculated but prior to the relevant Calculation Date, then the Gross Secured Leverage Ratio shall be calculated giving *pro forma* effect to such Incurrence, repayment, repurchase or redemption of Indebtedness, or such issuance, repurchase or redemption of Disqualified Stock or Preferred Stock, as if the same had occurred at the beginning of the applicable two full fiscal semi-annual periods.

For purposes of making the computation referred to above, Investments, acquisitions, dispositions, mergers, amalgamations, consolidations and discontinued operations (as determined in accordance with A-IFRS), in each case with respect to an operating unit of a business, and any operational changes that the Parent Guarantor or any Restricted Subsidiary has determined to make and/or made during or subsequent to such reference period and on or prior to or simultaneously with the Calculation Date shall be calculated on a *pro forma* basis assuming that all such Investments, acquisitions, dispositions, mergers, amalgamations, consolidations, discontinued operations and other operational changes (and the change of any associated fixed charge obligations and the change in EBITDAX resulting therefrom) had occurred on the first day of the two full fiscal semi-annual reference periods. If since the beginning of such period any Person that subsequently became a

Restricted Subsidiary or was merged with or into the Parent Guarantor or any Restricted Subsidiary since the beginning of such period shall have made any Investment, acquisition, disposition, merger, consolidation, amalgamation, discontinued operation or operational change, in each case with respect to an operating unit of a business, that would have required adjustment pursuant to this definition, then the Gross Secured Leverage Ratio shall be calculated giving *pro forma* effect thereto for such period as if such Investment, acquisition, disposition, discontinued operation, merger, amalgamation, consolidation or operational change had occurred at the beginning of the applicable two full fiscal semi-annual periods. If since the beginning of such period any Restricted Subsidiary is designated an Unrestricted Subsidiary or any Unrestricted Subsidiary is designated a Restricted Subsidiary, then the Gross Secured Leverage Ratio shall be calculated giving *pro forma* effect thereto for such period as if such designation had occurred at the beginning of the applicable two full fiscal semi-annual periods.

For purposes of this definition, whenever *pro forma* effect is to be given to any event, the *pro forma* calculations shall be made in good faith by a responsible financial or accounting officer of the Issuer. Any such *pro forma* calculation may include adjustments appropriate, in the reasonable good faith determination of the Issuer as set forth in an Officers' Certificate, to reflect operating expense reductions and other operating improvements or synergies reasonably expected to result from the applicable event on or prior to the date that is 12 months after such applicable event; provided that the aggregate amount of operating expense reductions and other operating improvements or synergies added to EBITDAX pursuant to the preceding paragraph, the second paragraph of the definition of Fixed Charge Coverage Ratio or the second paragraph of the definition of Net Leverage Ratio plus the aggregate amount of non-cash items excluded and resulting in an increase to Consolidated Net Income pursuant to clause (a) of the definition thereof shall not exceed, in any two consecutive semi-annual reporting periods, an amount equivalent to 20% of EBITDAX for the applicable two consecutive semi-annual reporting periods, prior to giving effect to such exclusions, add-backs or other adjustments.

For purposes of this definition, any amount in a currency other than U.S. dollars will be converted to U.S. dollars based on the average exchange rate for such currency for the most recent 12-month period immediately prior to the date of determination in a manner consistent with that used in calculating EBITDAX for the applicable period.

"guarantee" means a guarantee (other than by endorsement of negotiable instruments for collection in the ordinary course of business), direct or indirect, in any manner (including, without limitation, letters of credit and reimbursement agreements in respect thereof) (whether arising by virtue of partnership arrangements or by agreements to keep-well, to maintain financial statement conditions or otherwise), of all or any part of any Indebtedness or other obligations or entered into for the purposes of assuring in any other manner the obligee of such Indebtedness of the payment thereof or to protect such obligee against lost in respect thereof (in whole or in part).

"Guarantee" means any Subsidiary Guarantee and any guarantee of the obligations of the Issuer under the indenture and the Notes by the Parent Guarantor in accordance with the provisions of the indenture.

"Guarantor" means any Subsidiary Guarantor and the Parent Guarantor.

"Hedging Obligations" means, with respect to any Person, the obligations of such Person under:

(a) currency exchange, interest rate or commodity swap agreements (including commodity swaps, commodity options, forward commodity contracts, basis differential swaps, spot contracts, fixed price physical delivery contracts or other similar agreements or arrangements in respect of Hydrocarbons), currency exchange, interest rate or commodity cap agreements and currency exchange, interest rate or commodity collar agreements; and

(b) other agreements or arrangements designed to protect such Person against fluctuations in currency exchange, interest rates or commodity prices.

Notwithstanding the foregoing, agreements or obligations to physically sell any commodity at any index based price shall not be considered Hedging Obligations.

"holder" or "noteholder" means the Person in whose name a note is registered on the Registrar's books.

"Hydrocarbons" means oil, natural gas, casinghead gas, drip gasoline, natural gasoline, condensate, distillate, liquid hydrocarbons, gaseous hydrocarbons and all constituents, elements or compounds thereof and products refined or processed therefrom.

"Incur" means issue, assume, guarantee, incur or otherwise become liable for; provided, however, that any Indebtedness or Capital Stock of a Person existing at the time such person becomes a Subsidiary (whether by merger, amalgamation, consolidation, acquisition or otherwise) shall be deemed to be Incurred by such Person at the time it becomes a Subsidiary.

"Indebtedness" means, with respect to any Person:

(a) the principal and premium (if any) of any indebtedness of such Person, whether or not contingent, (a) in respect of borrowed money, (b) evidenced by bonds, notes, debentures or similar instruments or letters of credit or bankers' acceptances (or, without duplication, reimbursement agreements in respect thereof), (c) representing the deferred and unpaid purchase price of any property, which purchase price is due more than six months after the date of placing the property in service or taking delivery and title thereto, (d) in respect of Financing Lease Obligations, or (e) representing the net obligations under any Hedging Obligations, if and to the extent that any of the foregoing indebtedness would appear as a liability on a balance sheet (excluding the footnotes thereto) of such Person prepared in accordance with A-IFRS;

(b) to the extent not otherwise included, any obligation of such Person to be liable for, or to pay, as obligor, guarantor or otherwise, the obligations referred to in clause (a) of another Person (other than by endorsement of negotiable instruments for collection in the ordinary course of business); and

(c) to the extent not otherwise included, Indebtedness of another Person secured by a Lien on any asset owned by such Person (whether or not such Indebtedness is assumed by such Person); provided, however, that the amount of such Indebtedness will be the lesser of: (i) the Fair Market Value (as determined in good faith by the Issuer) of such asset at such date of determination, and (ii) the amount of such Indebtedness of such other Person;

provided, however, that notwithstanding the foregoing, Indebtedness shall be deemed not to include (1) Contingent Obligations Incurred in the ordinary course of business and not in respect of borrowed money; (2) deferred or prepaid revenues; (3) purchase price holdbacks in respect of a portion of the purchase price of an asset to satisfy warranty or other unperformed obligations of the respective seller; (4) in connection with the purchase by the Parent Guarantor or any Restricted Subsidiary of any business, any post-closing payment adjustments to which the seller may become entitled to the extent such payment is determined by a final closing balance sheet or such payment depends on the performance of such business after the closing; (5) Production Payments and Reserve Sales; (6) any obligation of a Person in respect of a Farm-In Agreement or similar arrangement whereby such Person agrees to pay all or a share of the drilling, completion or other expenses of an exploratory or development well (which agreement may be subject to a maximum payment obligation, after which expenses are shared in accordance with the working or participation interest therein or in accordance with the agreement of the parties) or perform the drilling, completion or other operation on such well in exchange for an ownership interest in an oil or gas property; and (7) in-kind obligations relating to net oil or natural gas balancing positions arising in the ordinary course of business.

"Independent Financial Advisor" means an accounting, appraisal or investment banking firm or consultant, in each case of nationally recognized standing, that is, in the good faith determination of the Issuer, qualified to perform the task for which it has been engaged.

"Initial Facility Agent" means Global Loan Agency Services Australia Pty Ltd (ACN 608 829 303) as agent of the finance parties (other than the Common Security Agents) under the RBL facility.

"Insolvency Proceeding" means (a) any voluntary or involuntary case or proceeding under any Bankruptcy Law with respect to the Issuer or the Guarantors, (b) any other voluntary or involuntary insolvency, reorganization or bankruptcy case or proceeding, or any receivership, liquidation, reorganization or other similar case or proceeding with respect to the Issuer or a Guarantor or with respect to any of its assets, (c) any liquidation, dissolution, reorganization or winding up of the Issuer or a Guarantor whether voluntary or involuntary and whether or not involving insolvency or bankruptcy (except to the extent permitted by the RBL facility or Notes Documents, as applicable) or (d) any assignment for the benefit of creditors or any other marshaling of assets and liabilities of the Issuer or a Guarantor.

"Intercreditor Agent" means Global Loan Agency Services Australia Pty Ltd (ACN 608 829 303), in its capacity as intercreditor agent for the Secured Parties (under and as defined in the Senior Lien Intercreditor Agreement) (other than the Intercreditor Agent and the Common Security Agents), or any successor intercreditor agent.

"Investment Grade Rating" means a rating equal to or higher than Baa3 (or the equivalent) by Moody's and BBB- (or the equivalent) by S&P and Fitch, or an equivalent rating by any other Rating Agency.

"Investment Grade Securities" means:

(a) securities issued or directly and fully guaranteed or insured by the Australian or the U.S. government or any agency or instrumentality thereof (other than Cash Equivalents),

(b) securities that have a rating equal to or higher than Baa3 (or equivalent) by Moody's and BBB- (or equivalent) by S&P, but excluding any debt securities or loans or advances between and among the Parent Guarantor and its Subsidiaries,

(c) investments in any fund that invests exclusively in investments of the type described in clauses (a) and (b), which fund may also hold immaterial amounts of cash pending investment and/or distribution, and

(d) corresponding instruments in countries other than the United States customarily utilized for high quality investments and in each case with maturities not exceeding two years from the date of acquisition.

"Investments" means, with respect to any Person, all investments by such Person in other Persons (including Affiliates) in the form of loans (including guarantees), advances or capital contributions (excluding accounts receivable, trade credit and advances to customers and commission, travel and similar advances to officers, employees and consultants made in the ordinary course of business), purchases or other acquisitions for consideration of Indebtedness, Equity Interests or other securities issued by any other Person and investments that are required by A-IFRS to be classified on the balance sheet of such Person in the same manner as the other investments included in this definition to the extent such transactions involve the transfer of cash or other property. For purposes of the definition of "Unrestricted Subsidiary" and the covenant described under "—Certain Covenants—Limitation on Restricted Payments":

(a) "Investments" shall include the portion (proportionate to the Parent Guarantor's equity interest in such Subsidiary) of the Fair Market Value (as determined in good faith by the Parent Guarantor) of the net assets of a Subsidiary of the Parent Guarantor at the time that such Subsidiary is designated an Unrestricted Subsidiary; provided, however, that upon a redesignation of such Subsidiary as a Restricted Subsidiary, the Parent Guarantor shall be deemed to continue to have a permanent "Investment" in an Unrestricted Subsidiary equal to an amount (if positive) equal to:

(i) the Parent Guarantor's "Investment" in such Subsidiary at the time of such redesignation, less

(ii) the portion (proportionate to the Parent Guarantor's equity interest in such Subsidiary) of the Fair Market Value (as determined in good faith by the Parent Guarantor) of the net assets of such Subsidiary at the time of such redesignation; and

(b) any property transferred to or from an Unrestricted Subsidiary shall be valued at its Fair Market Value (as determined in good faith by the Parent Guarantor) at the time of such transfer, in each case as determined in good faith by the Board of Directors of the Parent Guarantor.

Except as otherwise provided in the indenture, the amount of an Investment will be determined at the time the Investment is made and without giving effect to subsequent changes in value.

"Issue Date" means the date on which the Notes are originally issued.

"Junior Lien Obligations" means the Obligations with respect to other Indebtedness permitted to be Incurred under the indenture, which is by its terms intended to be secured by the Collateral on a basis junior to the Notes; provided such Lien is permitted to be Incurred under the indenture.

"Lien" means, with respect to any asset, any mortgage, lien, pledge, charge, security interest or similar encumbrance of any kind in respect of such asset, whether or not filed, recorded or otherwise perfected under applicable law (including any conditional sale or other title retention agreement, any lease in the nature thereof, any option or other agreement to sell or give a security interest in and any filing of or agreement to give any financing statement under the Uniform Commercial Code (or equivalent statutes) of any jurisdiction).

"Limited Condition Transaction" means (1) any Investment or acquisition (whether by merger, amalgamation, consolidation or other business combination or the acquisition of Capital Stock or otherwise, which may include, for the avoidance of doubt, a transaction that may constitute a Change of Control) whose consummation is not conditioned on the availability of, or on obtaining, third party financing, (2) any redemption, repurchase, defeasance, satisfaction and discharge or repayment of Indebtedness, Disqualified Stock or Preferred Stock requiring irrevocable notice in advance of such redemption, repurchase, defeasance, satisfaction and discharge or repayment, (3) any Restricted Payment requiring irrevocable notice in advance thereof, (4) any Asset Sale, (5) any asset sale or a disposition excluded from the definition of "Asset Sale," and (6) any combination of any of the foregoing; in each case as otherwise not prohibited by the indenture.

"Market Capitalization" means an amount equal to (1) the total number of issued and outstanding shares of Common Stock of the Parent Guarantor on the date of declaration of the relevant Restricted Payment multipled by (ii) the arithmetic mean of the closing price per share of such Common Stock for the 30 consecutive trading days on its primary stock exchange immediately preceding the date of the declaration of the relevant Restricted Payment.

"Moody's" means Moody's Investors Service, Inc or any successor to the rating agency business thereof.

"Mortgaged Properties" means each parcel of real estate and improvements thereto with respect to which a Mortgage is required to be granted on the Issue Date or thereafter pursuant to the covenant described under "—Security—After-Acquired Property."

"Mortgages" means, collectively, the mortgages, trust deeds, deeds of trust, deeds to secure debt, assignment of as-extracted collateral, fixture filing and other security documents delivered (and all amendments modifications and supplements thereto) with respect to Mortgaged Properties substantially in the form attached as an exhibit to the indenture (with such changes thereto as may be necessary to account for local law matters).

"Net Income" means, with respect to any Person, the net income (loss) of such Person and its Restricted Subsidiaries, determined in accordance with A-IFRS and before any reduction in respect of Preferred Stock dividends.

"Net Leverage Ratio" means, with respect to any date of determination, the ratio of (a) (i) Consolidated Total Indebtedness outstanding as of the last day of the then applicable two full fiscal semi-annual periods, less (ii) cash and Cash Equivalents as of such date to (b) EBITDAX for such two full fiscal semi-annual periods. In the event that the Parent Guarantor or any Restricted Subsidiary Incurs, repays, repurchases or redeems any Indebtedness or issues, repurchases or redeems Disqualified Stock or Preferred Stock subsequent to the commencement of the period for which the Net Leverage Ratio is being calculated but prior to the relevant Calculation Date, then the Net Leverage Ratio shall be calculated giving *pro forma* effect to such Incurrence, repayment, repurchase or redemption of Indebtedness, or such issuance, repurchase or redemption of Disqualified Stock or Preferred Stock, as if the same had occurred at the beginning of the applicable two full fiscal semi-annual periods.

For purposes of making the computation referred to above, Investments, acquisitions, dispositions, mergers, amalgamations, consolidations and discontinued operations (as determined in accordance with A-IFRS), in each case with respect to an operating unit of a business, and any operational changes that the Parent Guarantor or any Restricted Subsidiary has determined to make and/or made during or subsequent to such reference period and on or prior to or simultaneously with the Calculation Date shall be calculated on a *pro forma* basis assuming that all such Investments, acquisitions, dispositions, mergers, amalgamations, consolidations, discontinued operations and other operational changes (and the change of any associated fixed charge obligations and the change in EBITDAX resulting therefrom) had occurred on the first day of the two full fiscal semi-annual reference periods. If since the beginning of such period any Person that subsequently became a Restricted Subsidiary or was merged with or into the Parent Guarantor or any Restricted Subsidiary since the beginning of such period shall have made any Investment, acquisition, disposition, merger, consolidation, amalgamation, discontinued operation or operational change, in each case with respect to an operating unit of a business, that would have required adjustment pursuant to this definition, then the Net Leverage Ratio shall be calculated giving *pro forma* effect thereto for such period as if such Investment, acquisition, disposition, discontinued operation, merger, amalgamation, consolidation or operational change had occurred at the beginning of the applicable two full fiscal semi-annual periods. If since the beginning of such period any Restricted Subsidiary is designated an Unrestricted Subsidiary or any Unrestricted Subsidiary is designated a Restricted Subsidiary, then the Net Leverage Ratio shall be calculated giving *pro forma* effect thereto for such period as if such designation had occurred at the beginning of the applicable two full fiscal semi-annual periods.

For purposes of this definition, whenever *pro forma* effect is to be given to any event, the *pro forma* calculations shall be made in good faith by a responsible financial or accounting officer of the Issuer. Any such *pro forma* calculation may include adjustments appropriate, in the reasonable good faith determination of the Parent Guarantor as set forth in an Officers' Certificate, to reflect operating expense reductions and other operating improvements or synergies reasonably expected to result from the applicable event on or prior to the date that is 12 months after such applicable event; provided that the aggregate amount of operating expense reductions and other operating improvements or synergies added to EBITDAX pursuant to the preceding paragraph, the second paragraph of the definition of Fixed Charge Coverage Ratio or the second paragraph of the definition of Gross Secured Leverage Ratio plus the aggregate amount of non-cash items excluded and resulting in an increase to Consolidated Net Income pursuant to clause (a) of the definition thereof shall not exceed, in any two consecutive semi-annual reporting periods, an amount equivalent to 20% of EBITDAX for the applicable two consecutive semi-annual reporting periods, prior to giving effect to such exclusions, add-backs or other adjustments.

For purposes of this definition, any amount in a currency other than U.S. dollars will be converted to U.S. dollars based on the average exchange rate for such currency for the most recent 12-month period immediately prior to the date of determination in a manner consistent with that used in calculating EBITDAX for the applicable period.

"Net Proceeds" means the aggregate cash proceeds received by the Parent Guarantor or any Restricted Subsidiary in respect of any Asset Sale (including, without limitation, any cash received in respect of or upon the sale or other disposition of any Designated Non-cash Consideration received in any Asset Sale and any cash payments received by way of deferred payment of principal pursuant to a note or installment receivable or otherwise, but only as and when received, but excluding the assumption by the acquiring person of Indebtedness relating to the disposed assets or other consideration received in any other non-cash form), net of the direct costs relating to such Asset Sale and the sale or disposition of such Designated Non-cash Consideration (including, without limitation, legal, accounting and investment banking fees, and brokerage and sales commissions), and any relocation expenses Incurred as a result thereof, taxes paid or payable as a result thereof (including after taking into account any available tax credits or deductions and any tax sharing arrangements related solely to such disposition), amounts required to be applied to the repayment of principal, premium (if any) and interest on Indebtedness required (other than pursuant to clause (1) of the second paragraph of the covenant described under "—Certain Covenants—Asset Sales") to be paid as a result of such transaction, amounts paid in connection with the termination of Hedging Obligations related to Indebtedness repaid with such proceeds or hedging oil, natural gas and natural gas liquid production in notional volumes corresponding to the Oil and Gas Properties subject to such Asset Sale, and any deduction of appropriate amounts to be provided by the Parent Guarantor as a reserve in accordance with A-IFRS against any liabilities associated with the asset disposed of in such transaction and retained by the Parent Guarantor after such sale or other disposition thereof, including, without limitation, pension and other post-employment benefit liabilities and liabilities related to environmental matters or against any indemnification obligations associated with such transaction.

"Non-recourse Debt" means Indebtedness (1) as to which neither the Parent Guarantor nor any Restricted Subsidiaries (a) provides credit support of any kind (including any undertaking, agreement or instrument that would constitute Indebtedness), (b) is directly or indirectly liable as a guarantor or otherwise, or (c) constitutes the lender, except for Customary Recourse Exceptions; and as to which the lenders will not have any contractual recourse to the Capital Stock or assets of the Parent Guarantor or any Restricted Subsidiaries (other than (a) the Capital Stock of an Unrestricted Subsidiary or (b) pursuant to customary Liens on related arrangements under any oil and gas royalty trust or master limited partnership, except for Customary Recourse Exceptions.

"Notes Documents" means the indenture, the Notes, the Guarantees, the Security Documents, the Senior Lien Intercreditor Documents, the Second Lien Pari Passu Intercreditor Agreement and any Customary Intercreditor Agreement.

"Notes Obligations" means Obligations in respect of the Notes, the indenture, the Guarantees and the Security Documents (other than any Security Documents that do not secure the Notes Obligations).

"Obligations" means any principal, interest, penalties, fees, indemnifications, reimbursements (including, without limitation, reimbursement obligations with respect to letters of credit and bankers' acceptances), damages and other liabilities (including, without limitation, any interest, fees and expenses accruing subsequent to the filing of a petition in bankruptcy, reorganization or similar proceeding at the rate provided for in the indenture, whether or not such interest, fees or expenses are an allowed claim under any such proceedings or under applicable state, federal or foreign law) payable under the documentation governing any Indebtedness whether matured or unmatured, liquidated or unliquidated, primary or secondary, direct or indirect, absolute, fixed or contingent; provided, that Obligations with respect to the Notes shall not include fees or indemnifications in favor of third parties other than the Trustee and the holders of the Notes.

"Officers' Certificate" means a certificate signed on behalf of the Issuer or Parent Guarantor, as applicable, by two Authorized Officers of the Issuer or Parent Guarantor, as applicable, one of whom must be the principal executive officer, the principal financial officer, the treasurer or the principal accounting officer of the Issuer or Parent Guarantor, as applicable, which meets the requirements set forth in the indenture.

"Offshore Security Agent" means Citibank, N.A., London Branch as offshore security agent and trustee for the Secured Creditors (together with the Common Security Agents and the Intercreditor Agent) under and as defined in the Security Agency and Subordination Deed and any successor thereto in such capacity.

"Oil and Gas Business" means:

(a) the business of acquiring, exploring, exploiting, developing, producing, operating and disposing of interests in oil, natural gas, natural gas liquids, liquefied natural gas and other Hydrocarbons and mineral properties or products produced in association with any of the foregoing;

(b) the business of gathering, marketing, distributing, treating, processing, storing, refining, selling and transporting of any production from such interests or properties;

(c) any business relating to exploration for or development, production, treatment, processing, storage, refining, transportation or marketing of oil, gas and other minerals and products produced in association therewith; and

(d) any business or activity relating to, arising from, or necessary, appropriate, incidental or ancillary to the activities described in the foregoing clauses (a) through (c) of this definition.

"Oil and Gas Properties" means all properties, including equity or other ownership interests therein, owned by a Person that contain or are believed to contain oil and gas reserves or other reserves of Hydrocarbons.

"Onshore Security Agent" means Banco Citibank S.A. as onshore security agent for the Secured Creditors (together with the Common Security Agents and the Intercreditor Agent) under and as defined in the Security Agency and Subordination Deed and any successor thereto in such capacity.

"Opinion of Counsel" means a written opinion from legal counsel who is reasonably acceptable to the Trustee.

"Other Second Lien Obligations" means any other Indebtedness of the Parent Guarantor and Restricted Subsidiaries that is equally and ratably secured with the Notes as permitted by the indenture and is designated by the Issuer as an Other Second Lien Obligation in an Officers' Certificate delivered to the Trustee; provided that the authorized representative (or other agent) of the holders of such Pari Passu Indebtedness (and any Obligations in respect of such Pari Passu Indebtedness) shall have become a party to (and such holders shall be bound by the terms of) the Senior Lien Intercreditor Documents (to the extent required to become a party thereto by the terms thereof) and a Customary Intercreditor Agreement.

"Pari Passu Indebtedness" means: (a) with respect to the Issuer, the Notes and any Indebtedness that ranks *pari passu* in right of payment to the Notes; and (b) with respect to any Guarantor, its Guarantee and any Indebtedness that ranks *pari passu* in right of payment to such Guarantor's Guarantee.

"Permitted Business Investment" means any Investment made in the ordinary course of business or that is of a nature that is or shall have become customary in the Oil and Gas Business generally or in the geographic region in which such activities occur, including Investments or expenditures for actively exploiting, exploring for, acquiring, developing, distributing, producing, processing, gathering, marketing, transporting, storing oil, natural gas or other Hydrocarbons and minerals through agreements, transactions, interests or arrangements, including incorporated or unincorporated joint ventures, that permit one to share risks or costs, comply with regulatory requirements regarding local ownership or satisfy other objectives customarily achieved through the conduct of the Oil and Gas Business jointly with third parties, including:

(a) Investments in ownership interests in oil, natural gas, other Hydrocarbons and minerals properties, processing facilities, gathering systems, pipelines, storage facilities or related systems or ancillary real property interests;

(b) Investments in the form of or pursuant to operating agreements, working interests, royalty interests, mineral leases, processing agreements, Farm-In Agreements, Farm-Out Agreements, contracts for the sale, transportation or exchange of oil, natural gas, other Hydrocarbons and minerals, production sharing agreements, participation agreements, development agreements, area of mutual interest agreements, unitization agreements, pooling agreements, joint bidding agreements, service contracts, joint venture agreements, partnership agreements (whether general or limited), subscription agreements, stock purchase agreements, shareholder agreements and other similar agreements (including for limited liability companies) with third parties;

(c) Investments in direct or indirect ownership interests in drilling rigs and related equipment, including, without limitation, transportation equipment; and

(d) Investments in technology or infrastructure relating to renewable energy generation, energy storage, advanced fuels, carbon mitigation, carbon capture, hydrogen technologies or fuel cells, or other emissions reduction, or certificates or credits or analogous instruments or rights (howsoever described) representing or in respect of any of the foregoing, in each case that are consistent with the Parent Guarantor's environmental, social and governance strategy.

"Permitted Business Investments" shall include Investments in equity or other ownership interests in entities engaged in the activities described above.

"Permitted Investments" means:

(a) any Investment in the Parent Guarantor or any Restricted Subsidiary; provided, however, that the primary business of such Restricted Subsidiary is the Oil and Gas Business;

(b) any Investment in Cash Equivalents or Investment Grade Securities;

(c) any Investment by the Parent Guarantor or any Restricted Subsidiary in a Person whose primary business is the Oil and Gas Business, if as a result of such Investment (a) such Person becomes a Restricted Subsidiary, or (b) such Person, in one transaction or a series of related transactions, is merged, consolidated or amalgamated with or into, or transfers or conveys all or substantially all of its assets to, or is liquidated into, the Parent Guarantor or a Restricted Subsidiary;

(d) any Investment in securities or other assets not constituting Cash Equivalents and received in connection with an Asset Sale made pursuant to the provisions of "—Certain Covenants—Asset Sales" or any other disposition of assets not constituting an Asset Sale;

(e) loans and advances to officers or directors in the ordinary course of business for bona fide business purposes, taken together with all other advances made pursuant to this clause (e), not to exceed US$5.0 million at any one time outstanding;

(f) any Investment acquired by the Parent Guarantor or any Restricted Subsidiary (i) in exchange for any other Investment or accounts receivable incurred in the ordinary course of business held by the Parent Guarantor or such Restricted Subsidiary in connection with or as a result of a bankruptcy, workout, reorganization or recapitalization of the issuer of such other Investment or accounts receivable, (ii) as a result of a foreclosure by the Parent Guarantor or any Restricted Subsidiary with respect to any secured Investment or other transfer of title with respect to any secured Investment in default or (iii) litigation, arbitration or other disputes with Persons who are not Affiliates of the Parent Guarantor;

(g) Hedging Obligations permitted under clause (9) of the second paragraph of the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock";

(h) additional Investments by the Parent Guarantor or any Restricted Subsidiary having an aggregate Fair Market Value (as determined in good faith by the Parent Guarantor), taken together with all other Investments made pursuant to this clause (h) that are at that time outstanding, not to exceed the greater of (x) US$50.0 million and (y) 2.5% of the Parent Guarantor's Total Assets determined as of the date of such Investment (with the Fair Market Value of each Investment being measured at the time made and without giving effect to subsequent changes in value); provided, however, that if any Investment pursuant to this clause (i) is made in any Person that is not the Parent Guarantor or a Restricted Subsidiary at the date of the making of such Investment and such Person becomes the Parent Guarantor or a Restricted Subsidiary after such date, such Investment shall thereafter be deemed to have been made pursuant to clause (a) above and shall cease to have been made pursuant to this clause (i) for so long as such Person continues to be the Parent Guarantor or a Restricted Subsidiary;

(i) Investments the payment for which consists of Equity Interests of the Parent Guarantor (other than Disqualified Stock); provided, however, that such Equity Interests will not increase the amount available for Restricted Payments under clause (iii) of the definition of Cumulative Credit contained in "—Certain Covenants—Limitation on Restricted Payments" or constitute proceeds from an Equity Offering;

(j) any transaction to the extent it constitutes an Investment that is permitted by and made in accordance with the provisions of the second paragraph of the covenant described under "—Certain Covenants—Transactions with Affiliates" (except transactions described in clauses (2), (4), (7) and (12) of such paragraph);

(k) (x) guarantees issued in accordance with the covenants described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" and "—Certain Covenants—Future Guarantors," including, without limitation, any guarantee or other obligation issued or Incurred under the RBL facility in connection with any letter of credit issued for the account of the Parent Guarantor or any of its Subsidiaries (including with respect to the issuance of, or payments in respect of drawings under, such letters of credit) and (y) guarantees of performance or other obligations (other than Indebtedness) arising in the ordinary course in the Oil and Gas Business, including obligations under Hydrocarbon exploration, development, joint operating and related agreements and licenses, concessions or operating leases related to the Oil and Gas Business;

(l) Investments of a Restricted Subsidiary acquired after the Issue Date or of an entity merged into, amalgamated with, or consolidated with the Parent Guarantor or a Restricted Subsidiary in a transaction that is not prohibited by the first paragraph of the covenant described under "—Certain Covenants—Merger, Amalgamation, Consolidation or Sale of All or Substantially All Assets" after the Issue Date to the extent that such Investments were not made in contemplation of such acquisition, merger, amalgamation or consolidation and were in existence on the date of such acquisition, merger, amalgamation or consolidation;

(m) any Investment in any Subsidiary of the Parent Guarantor or any joint venture in connection with intercompany cash management arrangements or related activities arising in the ordinary course of business; and

(n) Permitted Business Investments.

"Permitted Invoice Discounting" means a customary limited recourse Petroleum invoice discounting or factoring arrangement (but not a Petroleum pre-export financing arrangement or similar financial accommodation), the proceeds of which are payable to an account that constitutes Collateral.

"Permitted Liens" means, with respect to any Person:

(a) pledges or deposits by such Person under workmen's compensation laws, unemployment insurance laws or similar legislation Incurred in the ordinary course of business;

(b) Liens imposed by law, such as landlord's, carriers', warehousemen's, mechanics', materialmen's, repairmen's, construction or other like Liens securing obligations in the ordinary course of business that are not overdue by more than 30 days or that are being contested in good faith by appropriate proceedings;

(c) Liens for taxes, assessments or other governmental charges or claims in the ordinary course of business that are not more than 30 days overdue or that are being contested in good faith by appropriate proceedings promptly instituted and diligently concluded;

(d) minor survey exceptions, minor encumbrances, easements or reservations of, or rights of others for, licenses, rights-of-way, sewers, electric lines, telegraph and telephone lines and other similar purposes, or zoning or other restrictions as to the use of real properties or Liens incidental to the conduct of the business of such Person or to the ownership of its properties which were not Incurred in connection with Indebtedness and which do not in the aggregate materially adversely affect the value of said properties or materially impair their use in the operation of the business of such Person;

(e) (i) Liens on assets of a Restricted Subsidiary that is not a Subsidiary Guarantor securing Indebtedness of such Restricted Subsidiary permitted to be Incurred pursuant to the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock";

(ii) Liens securing Indebtedness Incurred under any Credit Facility, including any letter of credit facility relating thereto, Incurred pursuant to clause (1) of the second paragraph described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock"; provided, that (x) any First Priority After-Acquired Property that secures First Priority Lien Obligations pursuant to this clause (ii) shall be added to the Collateral and a perfected second priority security interest shall be vested in the Common Security Agent as described under "—Security—After-Acquired Property" and (y) such First Priority Lien Obligations shall be subject to the Senior Lien Intercreditor Documents; provided, further, that to the extent Indebtedness Incurred pursuant to clause (1) of the second paragraph described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" is secured, such Indebtedness constituting First Priority Lien Obligations and Other Second Lien Obligations will be subject to the Senior Lien Intercreditor Agreement and any Junior Lien Obligations and Other Second Lien Obligations shall be subject to a Customary Intercreditor Agreement; and provided, further, that unsecured Indebtedness and Junior Lien Obligations shall not be exchanged for Other Second Lien Obligations or Indebtedness that is secured on a senior basis to the Notes pursuant to clause (1) of the second paragraph described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock";

(iii) Liens securing the Notes Obligations issued on the Issue Date;

(f) Liens existing on the Issue Date (other than Liens in securing indebtedness for borrowed money and Liens described in another clause of this definition);

(g) Liens on assets, property or shares of stock of a Person at the time such Person becomes a Subsidiary; provided, however, that such Liens are not created or Incurred in connection with, or in contemplation of, such other Person becoming such a Subsidiary; provided, further, however, that such Liens may not extend to any other property owned by the Parent Guarantor or any Restricted Subsidiary;

(h) Liens on assets or property (including Capital Stock) at the time the Parent Guarantor or a Restricted Subsidiary acquired the assets or property, including any acquisition by means of a merger, amalgamation or consolidation with or into any Restricted Subsidiary; provided, however, that such Liens are not created or Incurred in connection with, or in contemplation of, such acquisition; provided further, however, that the Liens may not extend to any other property owned by the Parent Guarantor or any Restricted Subsidiary (other than pursuant to after- acquired property clauses in effect with respect to such Lien at the time of acquisition on property of the type that would have been subject to such Lien notwithstanding the occurrence of such acquisition);

(i) Liens for the purpose of securing the payment of all or a part of the purchase price of, or Financing Lease Obligations Incurred for the purpose of financing all or any part of the purchase price, lease expense, charter expense, rental payments or cost of design, development, construction, transportation, installation, migration, expansion or improvement of property, plant or equipment used in the Oil and Gas Business and any other capital expenses or operating expenses in relation thereto (including any reasonably related fees or expenses incurred in connection therewith); provided that (a) the aggregate principal amount of Indebtedness secured by such Liens is permitted to be Incurred by clause (12)(ii) of the second paragraph of the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" and does not exceed the cost of the assets or property so acquired or repaired, improved or constructed plus fees and expenses in connection therewith and (b) such Liens are created within 180 days of repair, improvement, construction or acquisition of such assets or property and do not encumber any other assets or property of the Parent Guarantor or any Restricted Subsidiaries other than such assets or property and assets affixed or appurtenant thereto (including improvements);

(j) Liens securing Hedging Obligations not Incurred in violation of the indenture, which Liens may secure First Priority Lien Obligations or rank *pari passu* with the Liens securing the Notes Obligations provided that such Liens pursuant to this clause (j) securing (i) First Priority Lien Obligations shall be subject to the Senior Lien Intercreditor Documents and the authorized representative (or other agent) of the holders of such Indebtedness (and any Obligations in respect thereof) shall have become a party to (and the holders of such Indebtedness shall be bound by the terms of) the Senior Lien Intercreditor Documents, (ii) Other Second Lien Obligations shall be subject to the Senior Lien Intercreditor Documents and a Customary Intercreditor Agreement and the authorized representative (or other agent) of the holders of such Indebtedness (and any Obligations in respect thereof) shall have become a party to (and the holders of such Indebtedness shall be bound by the terms of) the Senior Lien Intercreditor Documents and a Customary Intercreditor Agreement or (iii) Junior Lien Obligations shall be subject to a Customary Intercreditor Agreement and the authorized representative (or other agent) of the holders of such Indebtedness (and any Obligations in respect thereof) shall have become a party to (and the holders of such Indebtedness shall be bound by the terms of) a Customary Intercreditor Agreement; provided, further, that with respect to Hedging Obligations relating to Indebtedness, such Lien extends only to the property securing such Indebtedness;

(k) Liens over purchased receivable assets, cargos or associated bank accounts arising under any Indebtedness permitted to be Incurred by clause (18) of the second paragraph of the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock";

(l) leases and subleases of real property that do not materially interfere with the ordinary conduct of the business of the Parent Guarantor or any of the Restricted Subsidiaries;

(m) Liens arising from Uniform Commercial Code financing statement filings regarding operating leases entered into by the Parent Guarantor and the Restricted Subsidiaries in the ordinary course of business;

(n) Liens in favor of the Issuer or any Guarantor;

(o) Liens for the purpose of securing the financing of all or any part of the purchase price, lease expense, charter expense, rental payments or cost of design, development, construction, transportation, installation, migration, expansion or improvement, replacement or repair of any FPSO, rig or production, processing, storage and/or transportation facility used or useful in the Oil and Gas Business in respect thereof; provided that (a) the aggregate principal amount of Indebtedness secured by such Liens is otherwise permitted to be Incurred by clause (12)(i) of the second paragraph of the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock" and does not exceed the cost of the assets or property so acquired, replaced, repaired, improved or constructed plus fees and expenses in connection therewith and (b) such Liens are created within 180 days of replacement, repair, improvement, construction or acquisition of such assets or property and do not encumber any other assets or property of the Parent Guarantor or any Restricted Subsidiaries other than such assets or property and assets affixed or appurtenant thereto (including improvements);

(p) deposits made in the ordinary course of business to secure liability to insurance carriers;

(q) Liens on the Capital Stock of Unrestricted Subsidiaries to the extent securing Non-recourse Debt of such Unrestricted Subsidiary;

(r) the licensing or sublicensing of intellectual property in the ordinary course of business and that does not materially interfere with the business of the Parent Guarantor and any Restricted Subsidiaries taken as a whole; provided that any such license or sublicense shall be subject to the covenant described under "—Certain Covenants—Asset Sales";

(s) Liens to secure any Refinancing Indebtedness as a whole, or in part, permitted to be Incurred by clause (14) of the second paragraph of the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock;" provided, however, that (w) such new Lien shall be limited to all or part of the same property that secured the original Lien (plus improvements on such property or proceeds or distributions thereof), (x) the Indebtedness secured by such Lien at such time is not increased to any amount greater than the sum of (A) the outstanding principal amount or, if greater, committed amount of such Refinancing Indebtedness at the time the original Lien became a Permitted Lien under the indenture, and (B) an amount necessary to pay any interest, premiums or defeasance costs required by the instruments governing such existing Indebtedness (whether such existing Indebtedness is redeemed pursuant to a tender offer, optional redemption or otherwise) and fees and expenses Incurred in connection therewith, (y) if the Indebtedness being refinanced, refunded, extended, renewed or replaced is secured by a Lien that is junior to the Liens securing the Notes, such new Lien shall be junior to the Liens securing the Notes and (z) if the

Indebtedness being refinanced, refunded, extended, renewed or replaced is secured by a lien that is pari passu to the Liens securing the Notes, such new Lien shall be either pari passu or junior to the Liens securing the Notes; provided, further, that such Refinancing Indebtedness Incurred constituting Junior Lien Obligations and Other Second Lien Obligations shall be subject to the Senior Lien Intercreditor Agreement or a Customary Intercreditor Agreement, as appropriate;

(t) Liens on equipment of the Parent Guarantor or any Restricted Subsidiary granted in the ordinary course of business to the Parent Guarantor's or such Restricted Subsidiary's client at which such equipment is located;

(u) judgment and attachment Liens not giving rise to an Event of Default and notices of *lis pendens* and associated rights related to litigation being contested in good faith by appropriate proceedings and for which adequate reserves have been made;

(v) Liens arising out of conditional sale, title retention, consignment or similar arrangements for the sale of goods entered into in the ordinary course of business based on the supplier's usual terms of sale;

(w) Liens (i) Incurred to secure cash management services or to implement cash pooling arrangements in the ordinary course of business and (ii) on cash and Cash Equivalents and letters of credit securing any surety and bonding requirements;

(x) other Liens over any other assets securing obligations the outstanding principal amount of which does not, taken together with the principal amount of all other obligations secured by Liens Incurred under this clause (x) that are at that time outstanding, exceed the greater of (i) US$150.0 million and (ii) 7.5% of the Parent Guarantor's Total Assets determined as of the date of Incurrence after giving *pro forma* effect to such Incurrence and the application of proceeds therefrom; provided that (i) First Priority Lien Obligations may not be secured under this clause (x), (ii) any Other Second Lien Obligations secured under this clause (x) shall be subject to the Senior Lien Intercreditor Documents and a Customary Intercreditor Agreement and the authorized representative (or other agent) of the holders of such Indebtedness (and any Obligations in respect thereof) shall have become a party to (and the holders of such Indebtedness shall be bound by the terms of) the Senior Lien Intercreditor Documents and a Customary Intercreditor Agreement and (iii) any Junior Lien Obligations secured under this clause (x) shall be subject to a Customary Intercreditor Agreement and the authorized representative (or other agent) of the holders of such Indebtedness (and any Obligations in respect thereof) shall have become a party to (and the holders of such Indebtedness shall be bound by the terms of) a Customary Intercreditor Agreement; provided, further, that unsecured Indebtedness and Junior Lien Obligations shall not be exchanged for Other Second Lien Obligations or Indebtedness that is secured on a senior basis to the Notes pursuant to this clause (x);

(y) Liens or deposits made in the ordinary course of business to secure the performance of statutory or regulatory obligations or surety or appeal, indemnity or performance bonds, warranty and contractual requirements, good faith deposits in connection with bids, tenders, contracts or leases or Liens over cash collateral provided in connection with any performance bonds issued to any governmental department or regulatory authority or similar party, or other obligations of a like nature incurred in the ordinary course of business;

(z) any amounts held by a trustee in the funds and accounts in favor of other trustees, agents and representatives under an indenture securing any revenue bonds issued for the benefit of the Parent Guarantor or any Restricted Subsidiary, under any indenture or other debt agreement, permitted to be incurred under the indenture, issued in escrow pursuant to customary escrow arrangements pending the release thereof, or under any indenture or other debt agreement pursuant to customary discharge, redemption or defeasance provisions; provided, however, that such Liens are solely for the benefit of the trustees, agents or representatives in their capacities as such and not for the benefits of the holders of the Indebtedness;

(aa) Liens arising by virtue of any statutory or common law provisions relating to netting or set-off arrangements as to deposit accounts or other funds maintained with a depository or financial institution for the purpose of netting debit and credit balances; provided, that (i) such deposit account is not a dedicated cash collateral account and (ii) such deposit account is not intended by the Parent Guarantor or any Restricted Subsidiary to provide collateral to the depositary institution;

(bb) Liens made in the ordinary course of business securing reimbursement obligations for letters of credit that encumber documents and other assets relating to such letters of credit and the products or proceeds thereof;

(cc) Liens in respect of Production Payments and Reserve Sales;

(dd) Liens arising under oil and natural gas leases or subleases, overriding royalty interests, assignments, Farm-Out Agreements, Farm-In Agreements, division orders, contracts for the sale, purchase, exchange, transportation, gathering or processing of Hydrocarbons, unitizations and pooling designations any encumbrance or restriction (including put and call arrangements) with respect to Capital Stock of any joint venture or similar arrangement pursuant to any joint venture or similar agreement; declarations, orders and agreements, development agreements, joint venture agreements, partnership agreements, operating agreements, royalties, royalty trusts, master limited partnerships, working interests, net profits interests, joint interest billing arrangements, participation agreements, production sales contracts, production payment agreements, royalty trust agreements, incentive compensation programs for geologists, geophysicists and other providers of technical services to the Parent Guarantor or a Restricted Subsidiary, area of mutual interest agreements, gas balancing or deferred production agreements, injection, repressuring and recycling agreements, salt water or other disposal agreements, seismic or geophysical permits or agreements, licenses, sublicenses and other agreements, which are customary in the Oil and Gas Business; provided, however, in all instances that such Liens are limited to the assets that are the subject of the relevant agreement, program, order, trust, partnership or contract; provided further that such Liens shall not secure Indebtedness for borrowed money;

(ee) Liens on pipelines or pipeline facilities that arise by operation of law;

(ff) any (i) interest or title of a lessor or sublessor under any lease, Liens reserved in oil, gas or other Hydrocarbons, minerals, leases for bonus, royalty or rental payments and for compliance with the terms of such leases; (ii) restriction or encumbrance that the interest or title of such lessor or sublessor may be subject to (including, without limitation, ground leases or other prior leases of the demised premises, mortgages, mechanics' liens, tax liens and easements); or (iii) subordination of the interest of the lessee or sublessee under such lease to any restrictions or encumbrance referred to in the preceding clause (ii);

(gg) Liens securing Junior Lien Obligations, provided that the Notes Obligations are secured on a senior priority basis to the obligations so secured until such time as such obligations are no longer secured by a Lien; provided, further, that Junior Lien Obligations secured under this clause (gg) shall be subject to a Customary Intercreditor Agreement and the authorized representative (or other agent) of the holders of such Indebtedness (and any Obligations in respect thereof) shall have become a party to (and the holders of such Indebtedness shall be bound by the terms of) a Customary Intercreditor Agreement;

(hh) Liens securing customary initial and margin deposits attaching to commodity trading accounts or other brokerage accounts incurred in the ordinary course of business;

(ii) other Liens that rank on a *pari passu* basis with the Notes Obligations, securing Indebtedness in an amount determined as of the date of Incurrence after giving *pro forma* effect to such Incurrence and the application of proceeds therefrom, that on a *pro forma* basis does not cause the Gross Secured Leverage Ratio of the Parent Guarantor to exceed 1.5 to 1.0; provided, further that such Obligations secured under this clause (ii) shall be subject to the Senior Lien Intercreditor Documents and a Customary Intercreditor Agreement and the authorized representative (or other agent) of the holders of such Indebtedness (and any Obligations in respect thereof) shall have become a party to (and the holders of such Indebtedness shall be bound by the terms of) the Senior Lien Intercreditor Documents and a Customary Intercreditor Agreement; and

(jj) Liens in favor of customs and revenue authorities arising as a matter of law to secure payments of customs duties in connection with the importation of goods.

Notwithstanding the foregoing, (i) to the extent Indebtedness Incurred pursuant to clause (11) of the second paragraph of the covenant described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock;" is secured by a Lien, such Indebtedness constituting First Priority Lien Obligations and Other Second Lien Obligations will be subject to the Senior Lien Intercreditor Agreement and any Junior Lien Obligations and Other Second Lien Obligations shall be subject to a Customary Intercreditor Agreement; and (ii) unsecured Indebtedness and Junior Lien Obligations shall not be exchanged for Other Second Lien Obligations or Indebtedness that is secured on a senior basis to the Notes pursuant to clause (11) under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock."

"Person" means any natural person, corporation, partnership, limited liability company, joint venture, association, joint stock company, trust, unincorporated organization, government or any agency or political subdivision thereof or any other entity.

"Petroleum" means any mineral, oil or relative hydrocarbon (including condensate and natural gas liquids) and natural gas existing in its natural condition in strata (but not including coal or bituminous shale or other stratified deposits from which oil can be extracted by destructive distillation).

"Petroleum Industry Standards" shall mean the Definitions for Oil and Gas Reserves promulgated by the Society of Petroleum Engineers (or any generally recognized successor) as in effect at the time in question.

"Post-Petition Claims" means, collectively, interest, fees, costs, expenses and other charges that pursuant to any RBL Facility Document continue to accrue after the commencement of any Insolvency Proceeding.

"Preferred Stock" means any Equity Interest with preferential right of payment of dividends or upon liquidation, dissolution, or winding up.

"Production Payments and Reserve Sales" means the grant or transfer by the Parent Guarantor or a Restricted Subsidiary to any Person of a royalty, overriding royalty, net profits interest, production payment (whether volumetric or dollar denominated), partnership or other interest in Oil and Gas Properties, reserves or the right to receive all or a portion of the production or the proceeds from the sale of production attributable to such properties where the holder of such interest has recourse solely to such production or proceeds of production, subject to the obligation of the grantor or transferor to operate and maintain, or cause the subject interests to be operated and maintained, in a reasonably prudent manner or other customary standard or subject to the obligation of the grantor or transferor to indemnify for environmental, title or other matters customary in the Oil and Gas Business, including any such grants or transfers pursuant to incentive compensation programs on terms that are reasonably customary in the Oil and Gas Business for geologists, geophysicists and other providers of technical services to the Parent Guarantor or a Subsidiary of the Parent Guarantor.

"Rating Agency" means (1) each of Moody's, Fitch and S&P and (2) with respect to the Notes, if Moody's, Fitch or S&P ceases to rate the Notes for reasons outside of the Issuer's control, a "nationally recognized statistical rating organization" within the meaning of Rule 17g-1 under the Exchange Act selected by the Parent Guarantor, Issuer or any direct or indirect parent of the Issuer as a replacement agency for Moody's, Fitch or S&P, as the case may be.

"Rating Category" means: (1) with respect to S&P and Fitch, any of the following categories: AAA, AA, A, BBB, BB, B, CCC, CC, C and D (or equivalent successor categories); and (2) with respect to Moody's, any of the following categories: Aaa, Aa, A, Baa, Ba, B, Caa, Ca, C and D (or equivalent successor categories).

"Rating Decline" means a decrease in the rating of the Notes by either of the Rating Agencies by one or more gradations (including gradations within Rating Categories as well as between Rating Categories) from the rating of the Notes on the date of the applicable occurrence referred to in clauses (a) or (c) of the definition of "Change of Control" under the indenture. In determining whether the rating of the Notes has decreased by one or more gradations, gradations within Rating Categories, namely + or – for S&P or Fitch, and 1, 2, and 3 for Moody's, will be taken into account; for example, in the case of S&P or Fitch, a rating decline either from BB+ to BB or BB- to B+ will constitute a decrease of one gradation.

"Refunding Capital Stock" means Equity Interests of the Parent Guarantor or contributions to the equity capital of the Parent Guarantor (other than any Disqualified Stock or any Equity Interests sold to a Subsidiary of the Parent Guarantor) that (a) are exchanged for or (b) the proceeds of the substantially concurrent sale of which are used to redeem, repurchase, retire or acquire, in each case, Retired Capital Stock or Restricted Indebtedness of the Parent Guarantor or any Guarantor.

"Restricted Investment" means an Investment other than a Permitted Investment.

"Restricted Subsidiary" means, with respect to any Person, any Subsidiary of such Person that is not an Unrestricted Subsidiary. Unless otherwise indicated in this "Description of the Notes," all references to Restricted Subsidiaries shall mean Restricted Subsidiaries of the Parent Guarantor, including the Issuer.

"Retired Capital Stock" means Equity Interests of the Parent Guarantor or any Guarantor that are redeemed, repurchased retired or otherwise acquired in exchange for, or out of the proceeds of Refunding Capital Stock.

"S&P" means S&P Global Ratings or any successor to the rating agency business thereof.

"Sale/Leaseback Transaction" means an arrangement relating to property now owned or hereafter acquired by the Parent Guarantor or a Restricted Subsidiary whereby the Parent Guarantor or such Restricted Subsidiary transfers such property to a Person and the Parent Guarantor or such Restricted Subsidiary leases it from such Person, other than leases between the Parent Guarantor and a Restricted Subsidiary or between Restricted Subsidiaries.

"SEC" means the Securities and Exchange Commission.

"Second Lien Authorized Representative" means, at any time, (a) in the case of the Notes Obligations with respect to of the Notes, the Trustee for the Notes, and (b) in the case of any other series of Additional Second Lien Obligations or Additional Second Lien Secured Parties that become subject to the Second Lien Pari Passu Intercreditor Agreement after the Issue Date, the Person named as the "Additional Junior Class Debt Representative" in the applicable joinder agreement.

"Second Lien Document" means (a) the Notes Documents and (b) each Additional Second Lien Document for each other series of Additional Second Lien Obligations.

"Second Lien Pari Passu Intercreditor Agreement" means that certain Second Lien Pari Passu Intercreditor Agreement to be entered into by the Common Security Agent, the Trustee and each of the other parties from time to time party thereto, in the form to be attached to the indenture, as may be amended, restated, supplemented or otherwise modified from time to time in accordance with its terms and in accordance with the indenture.

"Second Lien Obligations" means, collectively, (a) the Notes Obligations and (b) each other series of Additional Second Lien Obligations.

"Second Lien Secured Parties" means (a) the Secured Parties, and (b) the Additional Second Lien Secured Parties with respect to each other series of Additional Second Lien Obligations.

"Second Lien Security Documents" means (a) the Security Documents and (b) the Additional Second Lien Security Documents.

"Second Priority Lien Obligations" means (a) the Notes Obligations and (b) all Other Second Lien Obligations.

"Secured Bank Indebtedness" means any Bank Indebtedness that is secured by Permitted Liens Incurred or deemed Incurred pursuant to (i) clause (e)(ii) of the definition of Permitted Liens or (ii) clause (y) of the definition of Permitted Liens and that are, in each case, secured by Liens on the Collateral that are pari passu with the Liens securing any outstanding Indebtedness that was permitted to be incurred under clause (1) of the second paragraph described under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock."

"Secured Indebtedness" means any Consolidated Total Indebtedness secured by a Lien.

"Secured Parties" means, collectively, the Trustee and the holders of the Notes.

"Securities Act" means the Securities Act of 1933, as amended, and the rules and regulations of the SEC promulgated thereunder.

"Security Agency and Subordination Deed" means that certain security agency and subordination deed originally dated June 2, 2021, as amended and restated from time to time including most recently on November 16, 2023, between, among others, the Parent Guarantor, the Debtors, the Initial Facility Agent), the Intercreditor Agent, the lenders under the RBL facility, and the Common Security Agents, as it may be further amended, restated, supplemented or otherwise modified from time to time.

"Security Documents" means (i) any documents listed under "—Security Documents" above and (ii) any other collateral agreements, security agreements, pledge agreements, collateral assignments, mortgages or related agreements, in each case, as amended, supplemented, restated, renewed, refunded, replaced, restructured, repaid, refinanced or otherwise modified from time to time, creating the security interests in the Collateral for the benefit of the Common Security Agent and the other Secured Parties as contemplated by the indenture.

"Senior Lien Intercreditor Agreement" means that certain intercreditor agreement dated November 16, 2023 between among others, the Offshore Security Agent as offshore security agent and trustee, the Onshore Security Agent as onshore security agent, the Intercreditor Agent, the Initial Facility Agent and the Debtors, as it may be amended, restated, supplemented or otherwise modified from time to time.

"Senior Lien Intercreditor Documents" means (i) the Security Agency and Subordination Deed and (ii) the Senior Lien Intercreditor Agreement.

"Significant Subsidiary" means any Restricted Subsidiary that would be a "Significant Subsidiary" of the Parent Guarantor within the meaning of Rule 1-02 under Regulation S-X promulgated by the SEC (or any successor provision).

"Specified Transaction" means:

(a) solely for the purposes of determining the applicable cash balance, any contribution of capital (other than in respect of Disqualified Stock) to the Parent Guarantor;

(b) any Investment that results in a Person becoming a Restricted Subsidiary;

(c) any designation of a Subsidiary as a Restricted Subsidiary or an Unrestricted Subsidiary in compliance with the indenture;

(d) any acquisition of assets; or

(e) any Asset Sale:

  (i) that results in a Restricted Subsidiary ceasing to be a Subsidiary of the Parent Guarantor, or

  (ii) of a business, business unit, line of business or division of the Parent Guarantor or a Restricted Subsidiary, in each case whether by merger, amalgamation, consolidation, spin-off or otherwise.

"Stated Maturity" means, with respect to any security, the date specified in such security as the fixed date on which the final payment of principal of such security is due and payable, including pursuant to any mandatory redemption provision (but excluding any provision providing for the repurchase of such security at the option of the holder thereof upon the happening of any contingency beyond the control of the issuer unless such contingency has occurred).

"Subordinated Indebtedness" means (a) any Indebtedness of the Issuer that is by its terms subordinated in right of payment to the Notes, and (b) with respect to any Guarantor, any Indebtedness of such Guarantor that is by its terms subordinated in right of payment to its Guarantee.

"Subsidiary" means, with respect to any Person, (1) any corporation, association or other business entity (other than a partnership, joint venture or limited liability company) of which more than 50% of the total voting power of shares of Capital Stock entitled (without regard to the occurrence of any contingency and after giving effect to any voting or shareholders' agreement that effectively transfers voting power) to vote in the election of directors, managers or trustees thereof is at the time of determination owned or controlled, directly or indirectly, by such Person or one or more of the other Subsidiaries of that Person or a combination thereof, and (2) any partnership, joint venture or limited liability company of which (x) more than 50% of the capital accounts, distribution rights, total equity and voting interests or general and limited partnership interests, as applicable, are owned or controlled, directly or indirectly, by such Person or one or more of the other Subsidiaries of that Person or a combination thereof, whether in the form of membership, general, special or limited partnership interests or otherwise, and (y) such Person or any Subsidiary of such Person is a controlling general partner or otherwise controls such entity.

"Subsidiary Guarantee" means any guarantee of the obligations of the Issuer under the indenture and the notes by any Subsidiary Guarantor in accordance with the provisions of the indenture.

"Subsidiary Guarantor" means any Subsidiary that Incurs a Subsidiary Guarantee; provided that upon the release or discharge of such Person from its Subsidiary Guarantee in accordance with the indenture, such Subsidiary ceases to be a Subsidiary Guarantor.

"RBL facility" means the Syndicated Facility Agreement, dated as of November 16, 2023, among the Parent Guarantor, as borrower, Deutsche Bank AG, Sydney Branch, ING Belgium SA/NV, Macquarie Bank Limited and Shell Western Supply and Trading Limited, as mandated lead arrangers and bookrunners and the other lenders party thereto from time to time, as amended, restated, supplemented, waived, replaced (whether or not upon termination, and whether with the original lenders or otherwise), repaid, refunded, refinanced or otherwise modified from time to time, including any agreement extending the maturity thereof, refinancing or replacing all or any portion of the Indebtedness under such agreement or agreements or any successor or replacement agreement or agreements or increasing the amount loaned or issued thereunder or altering the maturity thereof.

"RBL Facility Documents" means the collective reference to the RBL facility, any notes issued pursuant thereto and the guarantees thereof, and the collateral documents relating thereto and the other "Finance Documents" (or analogous term) specified therein, as amended, supplemented, restated, renewed, refunded, replaced, restructured, repaid, refinanced or otherwise modified, in whole or in part, from time to time.

"Tax" means any tax, duty, levy, impost, assessment or other governmental charge in the nature of a tax (including penalties, interest and any other additions thereto). "Taxes" and "Taxation" shall be construed to have corresponding meanings.

"Tax Jurisdiction" (1) any jurisdiction in which the Issuer or any Guarantor is then incorporated, organized or resident for tax purposes or any political subdivision thereof or therein or (2) any jurisdiction from or through which payment is made by or on behalf of the Issuer or any Guarantor or any political subdivision thereof or therein.

"Total Assets" means the total consolidated assets of the Parent Guarantor and the Restricted Subsidiaries, as shown on the most recent balance sheet of the Parent Guarantor prepared in accordance with A-IFRS, calculated on a *pro forma* basis after giving effect to any subsequent acquisition or disposition of a Person or business.

"Trust Officer" means any officer or transaction manager within the corporate trust department of the Trustee, including any vice president, assistant vice president, trust officer, assistant trust officer or any other officer of the Trustee who customarily performs functions similar to those performed by the Persons:

(a) who at the time shall be such officers, respectively, or to whom any corporate trust matter is referred because of such person's knowledge of and familiarity with the particular subject and who will have direct responsibility for the administration of the indenture, and

(b) who shall have direct responsibility for the administration of the indenture.

"Trustee" means the party named as such in the indenture until a successor replaces it and, thereafter, means the successor.

"Uniform Commercial Code" or "UCC" means the New York Uniform Commercial Code as in effect from time to time.

"Unrestricted Subsidiary" means:

(a) any Subsidiary of the Parent Guarantor that at the time of determination shall be designated an Unrestricted Subsidiary by the Board of Directors of the Parent Guarantor in the manner provided below; and

(b) any Subsidiary of an Unrestricted Subsidiary;

The Parent Guarantor may designate any Subsidiary of the Parent Guarantor (including any newly acquired or newly formed Subsidiary) other than the Issuer to be an Unrestricted Subsidiary unless such Subsidiary or any of its Subsidiaries owns any Equity Interests or Indebtedness of, or owns or holds any Lien on any property of, the Parent Guarantor or any other Subsidiary of the Parent Guarantor that is not a Subsidiary of the Subsidiary to be so designated; provided, however, that

(a) the Subsidiary to be so designated and its Subsidiaries do not at the time of designation have and do not thereafter Incur any Indebtedness pursuant to which the lender has recourse to any of the assets of the Parent Guarantor or any of the Restricted Subsidiaries (other than pursuant to customary Liens or related arrangements under any oil and gas royalty trust or master limited partnership) other than Customary Recourse Exceptions; and

(b) (i) the Subsidiary to be so designated has total consolidated assets of US$1,000 or less; or

(ii) if such Subsidiary has consolidated assets greater than US$1,000, then such designation would be permitted under the covenant described under "—Certain Covenants—Limitation on Restricted Payments."

The Parent Guarantor may designate any Unrestricted Subsidiary to be a Restricted Subsidiary; provided, however, that immediately after giving effect to such designation:

(a) (1) the Parent Guarantor could Incur US$1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test described in the first paragraph under "—Certain Covenants—Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock and Preferred Stock," or (2) the Fixed Charge Coverage Ratio of the Parent Guarantor and Restricted Subsidiaries would be no less than such ratio immediately prior to such designation, in each case on a *pro forma* basis taking into account such designation, and

(b) no Event of Default shall have occurred and be continuing.

Any such designation by the Parent Guarantor shall be evidenced to the Trustee by promptly filing with the Trustee a copy of the resolution of the Board of Directors of the Parent Guarantor giving effect to such designation and an Officers' Certificate certifying that such designation complied with the foregoing provisions.

"U.S. Government Obligations" means securities that are:

(a) direct obligations of the United States of America for the timely payment of which its full faith and credit is pledged, or

(b) obligations of a Person controlled or supervised by and acting as an agency or instrumentality of the United States of America, the timely payment of which is unconditionally guaranteed as a full faith and credit obligation by the United States of America, which, in each case, are not callable or redeemable at the option of the issuer thereof, and shall also include a depository receipt issued by a bank (as defined in Section 3(a)(2) of the Securities Act) as custodian with respect to any such U.S. Government Obligations or a specific payment of principal of or interest on any such U.S. Government

Obligations held by such custodian for the account of the holder of such depository receipt; provided that (except as required by law) such custodian is not authorized to make any deduction from the amount payable to the holder of such depository receipt from any amount received by the custodian in respect of the U.S. Government Obligations or the specific payment of principal of or interest on the U.S. Government Obligations evidenced by such depository receipt.

"Volumetric Production Payments" means production payment obligations recorded as deferred revenue in accordance with A-IFRS, together with all undertaking and obligations in connection therewith.

"Voting Stock" of any Person as of any date means the Capital Stock of such Person that is at the time entitled to vote in the election of the Board of Directors of such Person.

"Weighted Average Life to Maturity" means, when applied to any Indebtedness or Disqualified Stock or Preferred Stock, as the case may be, at any date, the quotient obtained by dividing (1) the sum of the products of the number of years from the date of determination to the date of each successive scheduled principal payment of such Indebtedness or redemption or similar payment with respect to such Disqualified Stock or Preferred Stock multiplied by the amount of such payment, by (2) the sum of all such payments.

"Wholly Owned Restricted Subsidiary" is any Wholly Owned Subsidiary that is a Restricted Subsidiary.

"Wholly Owned Subsidiary" of any Person means a Subsidiary of such Person 100% of the outstanding Capital Stock or other ownership interests of which (other than directors' qualifying shares or shares required pursuant to applicable law) shall at the time be owned by such Person or by one or more Wholly Owned Subsidiaries of such Person.

CERTAIN TAX CONSEQUENCES

The following statements with regard to certain United States and Australian income tax consequences of an investment in the Notes and potential Australian withholding tax consequences of a payment by the Guarantors are based on the tax advice we have received. These statements do not take into account all the specific circumstances that may be relevant to a particular holder of the Notes. We urge you to consult your advisors concerning the consequences, as they relate to you and your specific circumstances, under Australian and United States federal, state and local tax laws, and the laws of any other relevant taxing jurisdiction of investing in the Notes.

Certain United States federal income tax consequences

The following discussion is a summary of certain United States federal income tax consequences generally applicable to the ownership and disposition of Notes by holders that acquire the Notes for cash at their original issue price pursuant to this offer. The summary is based on the Internal Revenue Code of 1986, as amended (the "Code"), United States Treasury Regulations, judicial decisions, published positions of the Internal Revenue Service (the "IRS") and other applicable authorities, all as in effect as of the date hereof and all of which are subject to change or differing interpretations (possibly with retroactive effect). The discussion does not address all of the tax consequences that may be relevant to a particular person or to persons subject to special treatment under United States federal income tax laws (such as broker dealers, insurance companies, banks and other financial institutions, expatriates, tax-exempt organizations, or persons that are, or hold their Notes through, partnerships or other pass-through entities), to United States Holders (as defined below) whose functional currency is not the United States dollar or to persons that hold the Notes as part of a straddle, hedge, conversion, synthetic security or constructive sale transaction for United States federal income tax purposes, all of whom may be subject to tax rules that differ from those summarized below. Moreover, this discussion does not consider the effect of any non-United States, state, local or other tax laws, the 3.8% Medicare contribution tax imposed on certain net investment income, special tax accounting rules as a result of an item of income being taken into account on an "applicable financial statement," or generally any other United States tax consequences other than United States federal income tax consequences that may be applicable to investors. This summary deals only with persons who hold the Notes as capital assets within the meaning of the Code (generally, property held for investment). No assurance can be given that the IRS would not assert, or that a court would not sustain, a position contrary to any of those set forth below. Holders are urged to consult their tax advisors as to the particular United States federal tax consequences to them of owning and disposing of the Notes, as well as the effects of state, local and non-United States tax laws.

For purposes of this discussion, a "United States Holder" means a beneficial owner of the Notes (as determined for United States federal income tax purposes) that is, or is treated as, a citizen or individual resident of the United States, a corporation (including any entity treated as a corporation for United States federal income tax purposes) created or organized in or under the laws of the United States or any political subdivision thereof or therein, an estate the income of which is subject to United States federal income taxation regardless of its source, or a trust if (i) a court within the United States is able to exercise primary supervision over the administration of the trust and one or more United States persons have the authority to control all substantial decisions of the trust or (ii) the trust has a valid election in effect under applicable United States Treasury Regulations to be treated as a United States person. A "Non-United States Holder" means any beneficial owner of a Note (other than a partnership or entity or arrangement treated as a partnership for United States federal income tax purposes) that is not a United States Holder.

If a partnership (including any entity or arrangement treated as a partnership or other pass-through entity for United States federal income tax purposes) is a holder of the Notes, the United States federal income tax treatment of a partner in the partnership will generally depend on the status of the partner and the activities of the partnership. Partners and partnerships are urged to consult their tax advisors as to the particular United States federal income tax consequences applicable to them.

We may be obligated to make payments on the Notes in excess of stated interest and principal in certain circumstances described under "Description of the Notes—Change of Control." We intend to take the position that there is no more than a remote chance that we will make such payments and that the Notes should accordingly not be treated as contingent payment debt instruments under United States Treasury Regulations. The remainder of this disclosure assumes that the Notes will not be treated as contingent payment debt instruments.

United States Holders

Payments of interest

Payments of interest on the Notes, including the payment of any Additional Amounts and any tax withheld from payments of interest, will be taxable to a United States Holder as ordinary interest income at the time such holder receives or accrues such amounts, in accordance with such holder's regular method of tax accounting.

Sale, exchange or other disposition of the Notes

Upon the sale, exchange or other disposition of a Note, a United States Holder will generally recognize capital gain or loss equal to the difference, if any, between the amount realized upon such sale, exchange or other disposition (other than amounts representing accrued and unpaid interest, which will be subject to tax as ordinary income to the extent not previously included in income) and such holder's adjusted tax basis in the Note at the time. A United States Holder's adjusted tax basis in a Note at any particular time generally will equal such United States Holder's initial investment in the Note. Such gain or loss generally will be United States source income or loss for United States foreign tax credit purposes. Moreover, any such gain or loss will be long-term capital gain or loss if the United States Holder's holding period with respect to the Note disposed of is more than one year at the time of the sale, exchange or other disposition. The deductibility of capital losses by a United States Holder is subject to limitations.

Non-United States Holders

Subject to the discussion of backup withholding below, a Non-United States Holder generally will not be subject to U.S. federal withholding tax on any payments of interest on the Notes, provided that the following conditions are satisfied:

- the Non-U.S. Holder does not actually or constructively own 10% or more of the total combined voting power of all classes of stock of the Issuer entitled to vote,

- the Non-U.S. Holder is not for U.S. federal income tax purposes a controlled foreign corporation related (directly or indirectly) to the Issuer through stock ownership,

- the Non-U.S. Holder is not a bank receiving interest on an extension of credit pursuant to a loan agreement entered into in the ordinary course of its business;

- the Non-U.S. Holder certifies to the applicable withholding agent that it is not a United States person on a properly completed Internal Revenue Service Form W-8BEN, W-8BEN-E or other such applicable form; and

- the Non-U.S. Holder provides any required information with respect to its direct and indirect U.S. owners as required pursuant to FATCA, or, if the Notes are held through, or such holder is, a "foreign financial institution" (as defined under FATCA), such foreign financial institution complies with its obligations under FATCA (either pursuant to an agreement with the U.S. government or in accordance with local law) or is otherwise exempt from FATCA.

Further, payments of interest (if the conditions described above are satisfied) and gain from the sale, redemption or other disposition of the Notes by a Non-U.S. Holder generally will not be subject to US federal income tax unless: (i) that payment of interest or gain is effectively connected with the conduct by that non-United States Holder of a trade or business in the U.S. (and, in the case of certain tax treaties, such payment of interest or gain is attributable to such Non-U.S. Holder's permanent establishment or fixed base in the United States); or (ii) in the case of any gain realized on the sale or exchange of a Note by an individual Non-United States Holder, that holder is present in the U.S. for 183 days or more in the taxable year of the sale, exchange or retirement and certain other conditions are met.

Backup withholding and information reporting

Information returns may be filed with the IRS in connection with payments on the Notes and the proceeds from a sale or other disposition of the Notes. A United States Holder may be subject to U.S. backup withholding on these payments if it fails to provide its tax identification number to the paying agent and comply with certain certification procedures or otherwise establish an exemption from backup withholding. The amount of any backup withholding from a payment to a United States Holder will be allowed as a credit against the holder's U.S. federal income tax liability and may entitle the United States Holder to a refund, provided that the required information is timely furnished to the IRS. Non-United States Holders may be required to comply with applicable certification procedures to establish that they are not United States Holders in order to avoid the application of such information reporting requirements and backup withholding.

Certain individuals and other United States Holders may be required to report information with respect to an investment in Notes not held through an account with a United States "financial institution" to the IRS. If a United States Holder fails to report the information required, the United States Holder could become subject to substantial penalties. United States Holders are urged to consult their tax advisors regarding the reporting requirements that may be imposed on them with respect to their ownership of the Notes.

Certain Australian withholding tax and income tax consequences

Non-Australian holders – general

The following is a general summary of the material Australian income tax consequences arising under the Income Tax Assessment Act 1936 and the Income Tax Assessment Act 1997 (together, the "Tax Act"), and any relevant regulations, rulings or judicial or administrative interpretations as of the date of this offering memorandum in relation to an investment in the Notes by a holder of the Notes who:

- is not a resident of Australia for Australian tax law purposes and does not carry on business in Australia through a permanent establishment or fixed base in Australia (a "Non-Resident Investor");
- holds the Notes on its own behalf (i.e., the holder is not, for example, a dealer in Securities or a Custodian); and
- purchased the Notes for cash at the original issue price pursuant to this offer.

The following is not intended to be, and should not be taken as, a comprehensive taxation summary for a holder. Each reference in the following taxation summary to a "Note" includes a reference to an "interest in a Note" as the context requires.

This general summary is not intended to be nor should it be construed to be legal or tax advice to any particular holder. Prospective holders are urged to contact their tax advisors for specific advice relating to their particular circumstances. Prospective holders who may be liable to taxation in jurisdictions other than Australia in respect of their acquisition, holding or disposal of Notes are particularly advised to consult their professional advisers as to whether they are so liable (and, if so, under the laws of which jurisdictions), since the following comments relate only to certain Australian taxation aspects of the Notes. In particular, holders should be aware that they may be liable to taxation under the laws of other jurisdictions in relation to payments in respect of the Notes even if such payments may be made without withholding or deduction for or on account of taxation under the laws of Australia.

Payments of principal and interest under the Notes by the Issuer

So long as the Issuer continues to be a non-resident of Australia, where the Notes issued by it are not attributable to an Australian permanent establishment of the Issuer, payments of principal and interest by the Issuer in respect of the Notes to a Non-Resident Investor should not be subject to Australian interest withholding tax.

Payments under the Guarantee by Australian resident Guarantors

The Guarantors may be required to make payments under the Guarantee in the event of default by the Issuer. Such payments by guarantors resident in Australia may be subject to Australian interest withholding tax depending on whether or not the amounts are characterized as interest or in the nature of, or in substitution for, interest. If an amount is not characterized as interest, the Guarantors should not have an obligation to deduct Australian interest withholding tax.

Australian interest withholding tax is generally payable at a rate of 10% of the gross amount of interest paid to a Non-Resident Investor, unless an exemption is available.While it is not finally resolved under Australian law whether a payment made under a guarantee falls under this definition of interest, the Australian Taxation Office has issued a Taxation Determination that states that it will regard a payment made by a guarantor (in respect of interest on debentures such as the Notes) as being in the nature of interest (and therefore subject to interest withholding tax), Consequently, the Commissioner may seek to collect Australian interest withholding tax on any guarantee payments made by an Australian resident Guarantor to a Non-Resident Investor to the extent that the payments relate to unpaid interest obligations (but not to the extent they relate to unpaid principal amounts). However, there is some doubt as to whether the Taxation Determination applies in the context of the Guarantee and whether the reasoning adopted in the Taxation Determination is strictly correct.

If it is ultimately determined that Australian interest withholding tax applies in these circumstances, a Non-Resident Investor may be entitled to additional amounts in certain circumstances. See "Description of the Notes—Additional Amounts" for further information.

Profits or gains on disposal or redemption of the Notes

Any profit or gain made on a disposal or a redemption of the Notes by a Non-Resident Investor who has never held the Notes in carrying on a business at or through a permanent establishment within Australia will not be subject to Australian income tax provided that such profit or gain does not have an Australian source. A gain arising on the sale of the Note by a Non-Resident Investor to another non-Australian resident where the Notes are sold outside Australia and all negotiations are conducted, and documentation executed, outside Australia, should generally not be regarded as having an Australian source.

Collection powers

The Australian Taxation Office and other revenue authorities in Australia have wide powers for the collection of unpaid tax debts. This can include issuing a notice to an Australian resident (such as an Australian resident Guarantor) requiring a deduction from any payment to a Non-Resident Investor in respect of any unpaid tax liabilities of that Non-Resident Investor. If an Australian resident Guarantor is served with such a notice, the Australian resident Guarantor intends to comply with that notice and make any deduction or withholding required by that notice. In such a circumstance, the relevant Non-Resident Investor will not be entitled to additional amounts in respect of that deduction or withholding.

Stamp duty

No stamp duty should be payable by a holder on the acquisition, transfer or redemption of Notes. Notes will not be subject to death, estate or succession duties imposed by Australia, or by any political subdivision or authority therein having power to tax, if held at the time of death.

Goods and Services Tax ("GST")

Neither the issue nor receipt of the Notes will give rise to a liability for GST in Australia on the basis that either the supply of Notes will not have a relevant connection with Australia or will comprise an input taxed financial supply. Furthermore, neither the payment of principal or interest on the Notes by the Issuer or the Guarantor, the redemption of the Notes, nor the disposal of the Notes, should give rise to a GST liability in Australia.

PLAN OF DISTRIBUTION

Subject to the terms and conditions of the purchase agreement, dated the date of this offering memorandum, among us and the initial purchasers, we have agreed to sell to the initial purchasers, and each of the initial purchasers has agreed, severally and not jointly, to purchase from us, the principal amount of Notes set forth opposite its name in the table below:

Initial purchaser	Principal Amount of Notes
Deutsche Bank Securities Inc.	US$227,500,000
ING Bank N.V., London Branch	US$122,500,000
Total	US$350,000,000

Subject to the terms and conditions set forth in the purchase agreement, the initial purchasers have agreed, severally and not jointly, to purchase all of the Notes sold under the purchase agreement if they purchase any of the Notes. If an initial purchaser defaults, the purchase agreement provides that a person who is satisfactory to the Issuer and the non-defaulting initial purchasers may purchase the defaulting initial purchaser's securities, the purchase commitments of the non-defaulting initial purchasers may be increased or the purchase agreement may be terminated. The initial purchasers have advised us that they propose initially to offer the Notes at the offering price set forth on the cover page of this offering memorandum. After the initial offering, the offering price or any other term of the offering may be changed without notice.

We have agreed to indemnify the initial purchasers against certain liabilities, including liabilities under the Securities Act, or to contribute to payments the initial purchasers may be required to make in respect of those liabilities.

Certain of the initial purchasers are not broker-dealers registered with the SEC and, therefore, may not make sales of any Notes in the United States or to U.S. persons except in compliance with applicable U.S. laws and regulations. To the extent that such initial purchaser intends to effect sales of the Notes in the United States, it will do so only through one or more U.S. registered broker-dealers or otherwise as permitted by applicable U.S. law.

Notes and Guarantees are not being registered under the Securities Act

Neither the Notes nor the Guarantees have been registered under the Securities Act, the securities law of any state of the United States or the securities laws of any other jurisdiction. The initial purchasers propose to offer the Notes for resale in transactions not requiring registration under the Securities Act, applicable state securities laws or the securities laws of any other jurisdiction, including sales pursuant to Rule 144A and Regulation S. The initial purchasers will not offer or sell the Notes except to persons they reasonably believe to be qualified institutional buyers or pursuant to offers and sales to persons that are not in the United States and are not, and are not acting for the account or benefit of, US persons. For a description of certain restrictions on eligible offerees and transfers of the Notes, see "Transfer restrictions."

In addition, until 40 days following the commencement of this offering, an offer or sale of Notes within the United States by a dealer (whether or not participating in the offering) may violate the registration requirements of the Securities Act unless the dealer makes the offer or sale in compliance with Rule 144A or another exemption from registration under the Securities Act. Each purchaser of the Notes will be deemed to have made acknowledgments, representations and agreements as described under "Transfer restrictions."

New issue of Notes

The Notes will constitute a new class of securities with no established trading market. We do not intend to list the Notes on any national securities exchange in the United States. Application will be made to the SGX-ST for the listing and quotation of the Notes on the SGX-ST. The offer and sale of the Notes is not conditioned on obtaining a listing of the Notes on the SGX-ST or any other exchange. We cannot assure you that the prices at which the Notes will sell in the market after this offering will not be lower than the initial offering price or that an active trading market for the Notes will develop and continue after this offering.

The initial purchasers have advised us that they currently intend to make a market in the Notes. However, they are not obligated to do so and they may discontinue any market-making activities with respect to the Notes at any time without notice. In addition, market-making activity will be subject to the limits imposed by the Securities Act and the Exchange Act. The ability of the initial purchasers and other market participants to make a market in the Notes may be impacted by changes in regulatory requirements applicable to the marketing, holding and trading of, and issuing quotations with respect to, the Notes. Accordingly, we cannot assure you as to the liquidity of or the trading market for the Notes. If an active trading market for the Notes does not develop, the market price and liquidity of the Notes may be adversely affected. If the Notes are traded, they may trade at a discount from their initial offering price depending on prevailing interest rates, the market for similar securities, our operating performance and financial condition, general economic conditions and other factors.

Settlement

We expect that delivery of the Notes will be made against payment therefor on or about the closing date specified on the cover page of this offering memorandum, which will be the fifth business day following the date of pricing of the Notes (this settlement cycle being referred to as "T+5"). Pursuant to Rule 15c6-1 under the Exchange Act, trades in the secondary market generally are required to settle in two business days, unless the parties to any trade expressly agree otherwise. Accordingly, purchasers who wish to trade Notes on any date prior to the second business day before delivery will be required, by virtue of the fact that the Notes initially will settle in T+5, to specify an alternative settlement cycle at the time of any such trade to prevent a failed settlement. Purchasers of the Notes who wish to make such trades should consult their own advisor.

No sales of similar securities

We have agreed that we will not, for a period from the date of the purchase agreement with the initial purchasers through and including the date that is the earlier of the date of payment for and delivery of the Notes and the termination of the purchase agreement, without first obtaining the prior written consent of the initial purchasers, offer, sell, contract to sell or otherwise dispose of any debt securities issued or guaranteed by the Parent Guarantor or any of the other Guarantors, except for the Notes sold to the initial purchasers pursuant to the purchase agreement.

Short positions, stabilizing transactions and penalty bids

In connection with the offering, the initial purchasers may purchase and sell the Notes in the open market. These transactions may include short sales and purchases on the open market to cover positions created by short sales. Short sales involve the sale by the initial purchasers of a greater principal amount of Notes than they are required to purchase in the offering. The initial purchasers must close out any short position by purchasing Notes in the open market. A short position is more likely to be created if the initial purchasers are concerned that there may be downward pressure on the price of the Notes in the open market after pricing that could adversely affect investors who purchase in the offering.

The initial purchasers may engage in stabilizing transactions, which consist of certain bids or purchases of the Notes made for the purpose of preventing or retarding a decline in the market price of the Notes while the offering is in progress. The initial purchasers may also impose penalty bids, which occur when a particular initial purchaser repays to another initial purchaser a portion of the underwriting discount received by it because the initial purchaser or its affiliates have repurchased Notes sold by or for the account of such initial purchaser in stabilizing or short covering transactions.

Similar to other purchase transactions, the initial purchasers' purchases to cover the syndicate short sales, as well as stabilizing transactions and penalty bids, may have the effect of raising or maintaining the market price of the Notes or preventing or retarding a decline in the market price of the Notes. As a result, the price of the Notes may be higher than the price that might otherwise exist in the open market.

Neither we nor any of the initial purchasers make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the Notes. In addition, neither we nor any of the initial purchasers make any representation that the representatives will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

Selling restrictions

Notice to prospective investors in Australia

Neither this offering memorandum nor any other prospectus or disclosure document (as defined in the Australian Corporations Act) in relation to the Notes or the Guarantees have been, or will be, lodged with ASIC. Each initial purchaser has represented and agreed that it (i) has not (directly or indirectly) offered, and will not offer for issue or sale and has not invited, and will not invite, applications for issue, or offers to purchase, the Notes in, to or from Australia (including an offer or invitation which is received by a person in Australia); and (ii) has not distributed or published, and will not distribute or publish, this offering memorandum, any information memorandum, advertisement or any other offering material relating to the Notes or Guarantees in Australia unless, in each case:

(a) the aggregate consideration payable by each offeree or invitee is at least A$500,000 (or its equivalent in other currencies, disregarding moneys lent by the offeror or its associates) or the offer or invitation otherwise does not require disclosure to investors in accordance with Part 6D.2 or Part 7.9 of the Australian Corporations Act;

(b) the offer or invitation is not made to a person who is a "retail client" within the meaning of section 761G of the Australian Corporations Act;

(c) such action complies with all applicable laws, regulations and directives; and

(d) such action does not require any document to be lodged with ASIC.

Notice to prospective investors in Canada

Prospective Canadian investors are advised that the information contained within this offering memorandum has not been prepared with regard to matters that may be of particular concern to Canadian investors. Accordingly, prospective Canadian investors should consult with their own legal, financial and tax advisors concerning the information contained within the offering memorandum and as to the suitability of an investment in the Notes in their particular circumstances.

The Notes may not be offered or sold, directly or indirectly, in any province or territory of Canada or to or for the benefit of any resident of any province or territory of Canada except pursuant to an exemption from the requirement to file a prospectus in the province or territory of Canada in which the offer or sale is made and only by a dealer duly registered under applicable laws in circumstances where an exemption from applicable registered dealer registration requirements is not available.

The Notes may be sold only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106 Prospectus Exemptions ("NI 45-106") or subsection 73.3(1) of the Securities Act (Ontario), and that are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the Notes must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this offering memorandum or any other offering material constituting an "offering memorandum" under applicable Canadian securities laws (including any amendment to any such documents) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 of National Instrument 33-105 Underwriting Conflicts ("NI 33-105"), the parties to this offering are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with an offering of Notes.

Prospective Canadian purchasers are hereby notified that: (i) the Issuer may be required to provide personal information pertaining to the purchasers as required to be disclosed in Schedule I of Form 45-106F1 under NI 45-106 (including, without limitation, the purchaser's name, address, telephone number and the aggregate purchase price of any Notes purchased) ("personal information"), which Form 45-106F1 may be required to be filed by the Issuer under NI 45-106, (ii) such personal information may be delivered to the Ontario Securities Commission (the "OSC") in accordance with NI 45-106, (iii) such personal information is collected indirectly by the OSC under the authority granted to it under the securities legislation of Ontario, (iv) such personal information is collected for the purposes of the administration and enforcement of the securities legislation of Ontario, and (v) the public official in Ontario who can answer questions about the OSC's indirect collection of such personal information is the Administrative Support Clerk at the OSC, Suite 1903, Box 55, 20 Queen Street West, Toronto, Ontario M5H 3S8, Telephone: (416) 593-3684. Prospective Canadian purchasers that purchase Notes in this offering will be deemed to have authorized the indirect collection of the personal information by the OSC, and to have acknowledged and consented to its name, address, telephone number and other specified information, including the aggregate purchase price paid by the purchaser, being disclosed to other Canadian securities regulatory authorities, and to have acknowledged that such information may become available to the public in accordance with requirements of applicable Canadian laws.

Upon receipt of this offering memorandum, each Canadian purchaser hereby confirms that it has expressly requested that all documents evidencing or relating in any way to the sale of the Notes described herein (including for greater certainty any purchase confirmation or any notice) be drawn up in the English language only. Par la re' ception de ce document, chaque acheteur canadien confirme par les pre' sentes qu'il a expresse'ment exige' que tous les documents faisant foi ou se rapportant de quelque manie' re que ce soit a' la vente des valeurs mobilie' res de' crites aux pre' sentes (incluant, pour plus de certitude, toute confirmation d'achat ou tout avis) soient re' dige' s en anglais seulement.

Prohibition of sales to EEA Retail Investors

Each initial purchaser has represented and agreed that it has not offered, sold or otherwise made available and will not offer, sell or otherwise make available any Notes to any EEA Retail Investor in the EEA.

For the purposes of this provision:

(a) the expression "EEA Retail Investor" means a person who is one (or more) of the following:

  (i) a retail client as defined in point (11) of Article 4(1) of MiFID II;

  (ii) a customer within the meaning of the Insurance Distribution Directive, where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; or

  (iii) not a qualified investor as defined in the Prospectus Regulation, and

(b) the expression "offer" includes the communication in any form and by any means of sufficient information on the terms of the offer and the Notes to be offered so as to enable an investor to decide to purchase or subscribe for the Notes.

Prohibition of Sales to United Kingdom Retail Investors and other Regulatory Restrictions

Each initial purchaser has represented and agreed that it has not offered, sold or otherwise made available and will not offer, sell or otherwise make available any Notes to any UK Retail Investor in the United Kingdom.

For the purposes of this provision:

(a) the expression "UK Retail Investor" means a person who is one (or more) of the following:

  (i) a retail client as defined in point (8) of Article 2 of Regulation (EU) No 2017/565 as it forms part of domestic law in the United Kingdom by virtue of the EUWA; or

  (ii) a customer within the meaning of the provisions of the FSMA and any rules or regulations made under the FSMA to implement the Insurance Distribution Directive, where that customer would not qualify as a professional client, as defined in point (8) of Article 2(1) of Regulation (EU) No 600/2014 as it forms part of domestic law in the United Kingdom by virtue of the EUWA; or

  (iii) not a qualified investor as defined in Article 2 of the UK Prospectus Regulation; and

(b) the expression "offer" includes the communication in any form and by any means of sufficient information on the terms of the offer and the Notes to be offered so as to enable an investor to decide to purchase or subscribe for the Notes.

In addition, each initial purchaser has represented and agreed that:

(i) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the FSMA) received by it in connection with the issue or sale of any Notes in circumstances in which Section 21(1) of the FSMA does not apply to the Issuer or the Guarantors; and

(ii) it has complied with and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to any Notes in, from or otherwise involving the United Kingdom.

Notice to prospective investors in Switzerland

This offering memorandum is not intended to constitute an offer or solicitation to purchase or invest in the Notes. Each initial purchaser has represented and agreed that the Notes may not be publicly offered, directly or indirectly, in Switzerland within the meaning of the Swiss Financial Services Act (the "FinSA") and no application has or will be made to admit the Notes to trading on any trading venue (exchange or multilateral trading facility) in Switzerland. Neither this offering memorandum nor any other offering or marketing material relating to the Notes constitutes a prospectus pursuant to the FinSA, and neither this offering memorandum nor any other offering or marketing material relating to the Notes may be publicly distributed or otherwise made publicly available in Switzerland.

Notice to prospective investors in Hong Kong

The Notes have not been and will not be offered or sold in Hong Kong by means of any document other than (i) to "professional investors" as defined in the Securities and Futures Ordinance (Cap. 571) of Hong Kong, as amended from time to time ("SFO"), and any rules made under the SFO; or (ii) in other circumstances which do not result in the document being a "prospectus" as defined in the Companies (Winding Up and Miscellaneous Provisions) Ordinance (Cap. 32) of Hong Kong, as amended from time to time (the "C(WUMP)O"), or which do not constitute an offer to the public within the meaning of the C(WUMP)O; and no advertisement, invitation or document relating to the Notes has been or will be issued or has been or will be in the possession of any person for the purpose of issue (in each case, whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public of Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than with respect to the Notes which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" as defined in the SFO and any rules made under the SFO.

Notice to prospective investors in Singapore

Each initial purchaser has acknowledged that this offering memorandum has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, each initial purchaser has represented, warranted and agreed that it has not offered or sold any Notes or caused the Notes to be made the subject of an invitation for subscription or purchase and will not offer or sell any Notes or cause the Notes to be made the subject of an invitation for subscription or purchase and has not circulated or distributed nor will it circulate or distribute this offering memorandum or any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the Notes, whether directly or indirectly, to any person in Singapore other than (i) to an institutional investor (as defined under Section 4A of the Securities and Futures Act 2001 of Singapore, as modified or amended from time to time (the "SFA")) pursuant to Section 274 of the SFA or (ii) to an accredited investor (as defined in Section 4A of the SFA) pursuant to and in accordance with the conditions specified in Section 275 of the SFA.

Notice to prospective investors in Japan

The Notes have not been and will not be registered under the Financial Instruments and Exchange Act of Japan (Act No. 25 of 1948, as amended) (the "FIEA"). Accordingly, the Notes have not been offered or sold and will not be offered or sold, directly or indirectly, in Japan or to, or for the account or benefit of, any resident of Japan (as defined under Item 5, Paragraph 1, Article 6 of the Foreign Exchange and Foreign Trade Act (Act No. 228 of 1949, as amended)) or to others for re-offering or resale, directly or indirectly, in Japan or to, or for the account or benefit of, any resident of Japan except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the FIEA and any other applicable laws, regulations and ministerial guidelines of Japan.

Notice to prospective investors in the Republic of Korea

The Notes have not been and will not be registered under the Financial Investment Services and Capital Markets Act (the "FSCMA"). None of the Notes may be offered, sold or delivered, directly or indirectly, in Korea or to any Korean resident (as such term is defined in the Foreign Exchange Transaction Law) for a period of one (1) year from the date of issuance of the Notes, except (i) to or for the account or benefit of a Korean resident which falls within certain categories of "professional investors" as specified in the FSCMA, its Enforcement Decree and the Regulation on Securities Issuance and Disclosure, in the case that the Notes are issued as bonds other than convertible bonds, bonds with warrants or exchangeable bonds, and where other relevant requirements are further satisfied, or (ii) as otherwise permitted under applicable Korean laws and regulations.

Notice to prospective investors in Taiwan

The Notes have not been and will not be registered with the Financial Supervisory Commission of Taiwan, the Republic of China ("Taiwan") pursuant to relevant securities laws and regulations and the Notes may not be sold, issued or offered within Taiwan through a public offering or in circumstances which constitutes an offer within the meaning of the Securities and Exchange Act of Taiwan that requires a registration or approval of the Financial Supervisory Commission of Taiwan. No person or entity in Taiwan has been authorized to offer, sell, give advice regarding or otherwise intermediate the offering and sale of the Notes in Taiwan.

Other relationships

The initial purchasers and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. They have received, or may in the future receive, customary fees and commissions for these transactions. Affiliates of Deutsche Bank Securities Inc. and ING Bank N.V., London Branch are lenders under our RBL facility and may receive a portion of the proceeds from this offering in connection with the repayment of indebtedness under that facility. See "Use of proceeds."

In addition, in the ordinary course of their business activities, the initial purchasers and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers. Such investments and securities activities may involve securities and/or instruments of ours or our affiliates. If any of the initial purchasers or their affiliates has a lending relationship with us, those initial purchasers or their affiliates routinely hedge, and the other of those initial purchasers may hedge, their credit exposure to us in line with their customary risk management policies. Typically, these initial purchasers and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities, including potentially the Notes offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the Notes offered hereby. The initial purchasers and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

TRANSFER RESTRICTIONS

Because of the following restrictions, investors are advised to consult legal counsel prior to making any offer, resale, pledge or transfer of Notes.

Offers and sales by the initial purchasers

The Notes and the Guarantees have not been, and will not be, registered under the Securities Act or the securities laws of any state or other jurisdiction and may not be offered, sold or delivered in the United States or to, or for the account or benefit of, any U.S. person (as defined in Regulation S), except pursuant to an effective registration statement or in a transaction not subject to the registration requirements of the Securities Act or in accordance with an applicable exemption from the registration requirements thereof. Accordingly, the Notes are being offered and sold hereunder only:

- within the United States to persons reasonably believed to be qualified institutional buyers in accordance with Rule 144A, and

- outside the United States to persons that are not U.S. persons and are not acting for the account or benefit of a U.S. person in accordance with Regulation S.

Investors' representations and restrictions on resale

Each purchaser of the Notes offered hereunder will be deemed, in making its purchase, to have represented and agreed as follows (terms used in this section that are defined in Rule 144A or in Regulation S are used in this section as defined in those rules or regulations):

1. The purchaser either (a)(1) is a qualified institutional buyer, (2) is aware that the sale of the Notes to it is being made in reliance on Rule 144A and (3) is acquiring such Notes for its own account or the account of one or more other qualified institutional buyers or (b)(1) is a purchaser that is outside the United States, not a U.S. person and not acting for the account or benefit of a U.S. person and (2) is aware that the sale of the Notes to it is being made in reliance on Regulation S;

2. The purchaser understands that the Notes have not been and will not be registered under the Securities Act and they may not be offered, sold or delivered in the United States or to, or for the account or benefit of, any U.S. person except as set forth below;

3. The purchaser understands and agrees that such Notes are being offered only in a transaction not involving any public offering within the meaning of the Securities Act, and that any future resale, pledge or transfer of such Notes on which the legend set forth below appears, may be made only (A) by an initial purchaser (i) to the Issuer, (ii) to a person whom the seller reasonably believes is a qualified institutional buyer acquiring for its own account or for the account of one or more other qualified institutional buyers in a transaction meeting the requirements of Rule 144A (if available), (iii) outside the United States to a purchaser that is not a U.S. person and is not acting for the account or benefit of a U.S. person in an offshore transaction meeting the requirements of Rule 903 or Rule 904 of Regulation S, (iv) pursuant to an exemption from registration under the Securities Act provided by Rule 144 (if available) (resales described in (i)-(iv), "Safe Harbor Resales") or (B) by a subsequent purchaser, in a Safe Harbor Resale or pursuant to any other available exemption from the registration requirements under the Securities Act (provided that as a condition to the registration of transfer of any Notes otherwise than in a Safe Harbor Resale, the Issuer, the Parent Guarantor or the Trustee may, in circumstances that any of them deems appropriate, require evidence, in addition to that required pursuant to clause (4) below, that it, in its absolute discretion, deems necessary or appropriate to evidence compliance with such exemption and with any state securities laws that may be applicable) or (C) pursuant to an effective registration statement under the Securities Act, in each case in accordance with any applicable securities laws of any state or other jurisdiction of the United States or other jurisdictions;

4. The purchaser will, and each subsequent holder is required to, notify any purchaser of Notes from it of the resale restrictions referred to in (3) above, if then applicable;

5. The purchaser understands and agrees that (A) the Notes initially offered to qualified institutional buyers in reliance on Rule 144A will be represented by Restricted Global Notes, and (B) with respect to any transfer of any interest in Restricted Global Notes, (i) if to transferees that take delivery in the form of interests in Restricted Global Notes, the Trustee will not require any written certification from the transferor or the transferee, and (ii) if to transferees that take delivery in the form of interests in the Regulation S Global Note, the Trustee will require written certification from the transferor (in the form(s) provided in the indenture), the form of which can be obtained from the Trustee, to the effect that the transfer complies with Rule 903 or Rule 904 of Regulation S;

6. Either (a) it is not a pension, profit-sharing or other employee benefit plan that is subject to ERISA or Section 4975 of the Code or any similar provision of applicable federal, state, local, foreign or other law ("Similar Law"), and it is not purchasing the Notes on behalf of or with the assets of any such plan or (b) its purchase and holding of the Notes will not constitute or result in a non-exempt prohibited transaction under ERISA or Section 4975 of the Code or a violation of Similar Law;

7. The purchaser understands that the Notes sold in reliance on Rule 144A will bear a legend to the following effect unless otherwise agreed with us:

   "NEITHER THIS SECURITY NOR ANY BENEFICIAL INTEREST HEREIN HAS BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"). THE HOLDER HEREOF, BY PURCHASING THIS SECURITY, AGREES FOR THE BENEFIT OF KAROON USA FINANCE INC (THE "ISSUER"), KAROON ENERGY LIMITED (THE "PARENT GUARANTOR"), THE SUBSIDIARY GUARANTORS OF THIS SECURITY UNDER THE INDENTURE (TOGETHER WITH THE PARENT GUARANTOR, THE "GUARANTORS"), THE TRUSTEE AND ANY NOTE REGISTRAR THAT THIS SECURITY AND BENEFICIAL INTERESTS HEREIN MAY BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED ONLY (1) TO THE ISSUER OR THE PARENT GUARANTOR, (2) SO LONG AS THIS SECURITY IS ELIGIBLE FOR RESALE PURSUANT TO RULE 144A UNDER THE SECURITIES ACT ("RULE 144A"), TO A PERSON WHO THE SELLER REASONABLY BELIEVES IS A QUALIFIED INSTITUTIONAL BUYER (AS DEFINED IN RULE 144A) PURCHASING FOR ITS OWN ACCOUNT OR THE ACCOUNT OF ONE OR MORE OTHER QUALIFIED INSTITUTIONAL BUYERS IN ACCORDANCE WITH RULE 144A, (3) OUTSIDE THE UNITED STATES TO A PURCHASER THAT IS NOT A U.S. PERSON AND IS NOT ACTING FOR THE ACCOUNT OR BENEFIT OF A U.S. PERSON IN AN OFFSHORE TRANSACTION COMPLYING WITH RULE 903 OR RULE 904 (AS APPLICABLE) OF REGULATION S UNDER THE SECURITIES ACT, (4) PURSUANT TO AN EXEMPTION FROM REGISTRATION IN ACCORDANCE WITH RULE 144 UNDER THE SECURITIES ACT (IF AVAILABLE), OR (5) PURSUANT TO AN EFFECTIVE REGISTRATION STATEMENT UNDER THE SECURITIES ACT, IN EACH SUCH CASE IN ACCORDANCE WITH ANY APPLICABLE SECURITIES LAWS OF ANY STATE OR OTHER JURISDICTION OF THE UNITED STATES OR OTHER JURISDICTIONS. THE HOLDER HEREOF, BY PURCHASING THIS SECURITY OR BY ACQUIRING SUCH BENEFICIAL INTEREST, REPRESENTS AND AGREES FOR THE BENEFIT OF THE ISSUER, THE GUARANTORS, THE TRUSTEE AND ANY NOTE REGISTRAR THAT IT WILL NOTIFY ANY PURCHASER OF THIS SECURITY OR A BENEFICIAL INTEREST HEREIN FROM IT OF THE RESALE RESTRICTIONS REFERRED TO ABOVE. IN ANY CASE, THE HOLDER HEREOF WILL NOT, DIRECTLY OR INDIRECTLY, ENGAGE IN ANY HEDGING TRANSACTION WITH REGARD TO INTERESTS IN THIS SECURITY EXCEPT AS PERMITTED BY THE SECURITIES ACT.

ANY TRANSFER OF A BENEFICIAL INTEREST IN THIS SECURITY IN VIOLATION OF THE FOREGOING SHALL BE NULL AND VOID AB INITIO AND WILL NOT OPERATE TO TRANSFER ANY RIGHTS TO THE TRANSFEREE, NOTWITHSTANDING ANY NOTICE OR INSTRUCTIONS TO THE CONTRARY TO THE ISSUER, THE TRUSTEE, THE NOTE REGISTRAR OR ANY INTERMEDIARY.

THIS LEGEND WILL BE REMOVED ONLY IN THE CIRCUMSTANCES SPECIFIED IN THE INDENTURE."

8. If the purchaser is not in the United States, is not a U.S. person and is not acting for the account or benefit of a U.S. person, it understands that the Notes offered in reliance on Regulation S initially will be represented by the Regulation S Global Note and that interests therein may be held only through Euroclear or Clearstream, Luxembourg through and including the 40th day after the later of the commencement of the offering of the Notes and the closing date of the offering of the Notes. The purchaser further understands that the Regulation S Global Note will bear a legend to the following effect, unless we determine otherwise in accordance with applicable law:

   "THIS SECURITY HAS NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), AND MAY NOT BE OFFERED, SOLD OR DELIVERED IN THE UNITED STATES OR TO, OR FOR THE ACCOUNT OR BENEFIT OF, ANY U.S. PERSON, UNLESS SUCH SECURITIES ARE REGISTERED UNDER THE SECURITIES ACT OR AN EXEMPTION FROM THE REGISTRATION REQUIREMENTS THEREOF IS AVAILABLE OR SUCH SECURITIES ARE OFFERED, SOLD OR DELIVERED IN A TRANSACTION NOT SUBJECT TO SUCH REGISTRATION REQUIREMENTS. THE FOREGOING SHALL NOT APPLY FOLLOWING THE EXPIRATION OF FORTY DAYS FROM THE LATER OF (i) THE DATE ON WHICH THESE SECURITIES WERE FIRST OFFERED AND (ii) THE DATE OF ISSUANCE OF THESE SECURITIES.

   ANY TRANSFER OF A BENEFICIAL INTEREST IN THIS SECURITY IN VIOLATION OF THE FOREGOING SHALL BE NULL AND VOID AB INITIO AND WILL NOT OPERATE TO TRANSFER ANY RIGHTS TO THE TRANSFEREE, NOTWITHSTANDING ANY NOTICE OR INSTRUCTIONS TO THE CONTRARY TO THE ISSUER, THE TRUSTEE, THE NOTE REGISTRAR OR ANY INTERMEDIARY."

9. The purchaser (i) has not (directly or indirectly) offered, and will not offer for issue or sale and has not invited, and will not invite, applications for issue, or offers to purchase, the Notes in, to or from Australia (including an offer or invitation which is received by a person in Australia); and (ii) has not distributed or published, and will not distribute or publish, this offering memorandum, any information memorandum, advertisement or any other offering material relating to the Notes or Guarantees in Australia unless, in each case:

   (a) the aggregate consideration payable by each offeree or invitee is at least A$500,000 (or its equivalent in other currencies, disregarding moneys lent by the offeror or its associates) or the offer or invitation otherwise does not require disclosure to investors in accordance with Part 6D.2 or Part 7.9 of the Australian Corporations Act;

   (b) the offer or invitation is not made to a person who is a "retail client" within the meaning of section 761G of the Australian Corporations Act;

   (c) such action complies with all applicable laws, regulations and directives; and

   (d) such action does not require any document to be lodged with ASIC.

The purchaser acknowledges that the Issuer, the Guarantors, the initial purchasers, the Trustee, the Note Registrar and others will rely upon the truth and accuracy of the foregoing acknowledgments, representations, warranties and agreements, and agrees that if any of the acknowledgments, representations or warranties deemed to have been made by it by its purchase of Notes are no longer accurate, it shall promptly notify us and the initial purchasers. If it is acquiring any Notes as a fiduciary or agent for one or more investor accounts, it represents that it has sole investment discretion with respect to each such account and it has full power to make the foregoing representations, warranties and agreements on behalf of each such account.

Each purchaser of Notes will be deemed to have represented and agreed that it understands that with respect to any transfer of interests in the Regulation S Global Note, on or prior to the 40th day after the later of the commencement of the offering and the closing date, if to a transferee who takes delivery in the form of an interest in the Restricted Global Note, the Trustee will require written certification from the transferee or transferor, as the case may be, (in the form(s) provided in the indenture) to the effect that (i) such transferee is purchasing the Notes for its own account or for accounts as to which it exercises sole investment discretion and that it and, if applicable, each such account is a qualified institutional buyer within the meaning of Rule 144A, in each case, in a transaction meeting the requirements of Rule 144A and in accordance with any applicable securities laws of any state or other jurisdiction of the United States or any other jurisdiction or (ii) the transferor did not purchase such Notes as part of the initial distribution thereof and the transfer is being effected pursuant to and in accordance with an applicable exemption from the registration requirements of the Securities Act and the transferor has delivered to the Trustee such additional evidence that we or the Trustee may require as to compliance with such available exemption.

For further discussion of the requirements (including the presentation of transfer certificates) under the indenture to effect exchanges or transfers of interests in Global Notes and of Certificated Notes, see “Description of the Notes—Transfer and Exchange.”

We recognize that none of DTC, Euroclear or Clearstream, Luxembourg in any way undertakes to, and none of DTC, Euroclear or Clearstream, Luxembourg shall have any responsibility to, monitor or ascertain the compliance of any transactions in the Notes with any exemptions from registration under the Securities Act or of any other state or federal securities law.

LEGAL MATTERS

Certain legal matters with respect to the Notes and the Guarantees will be passed upon for the Issuer and Guarantors by Allen Overy Shearman Sterling, Sydney, Australia, as to matters of New York, U.S. federal securities, English law and Australian law. Certain United States legal matters in connection with the offering of the Notes and Guarantees will be passed upon for the initial purchasers by Sullivan & Cromwell, Sydney, Australia.

INDEPENDENT AUDITORS

The consolidated financial statements of Karoon Energy Limited as of and for the transitional financial year ended December 31, 2023 and as of and for the financial years ended June 30, 2023 and 2022, included in this offering memorandum, have been audited by PricewaterhouseCoopers, independent auditors, as stated in their reports dated February 29, 2024, August 23, 2023 and August 25, 2022, respectively, appearing herein.

With respect to the unaudited condensed consolidated financial statements of Karoon Energy Limited as of and for the half-year ended December 31, 2022, included in this offering memorandum, PricewaterhouseCoopers reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, their separate report dated February 22, 2023 appearing herein states that they did not audit and they do not express an opinion on the unaudited condensed consolidated financial statements. Accordingly, the degree of reliance of their report on such information should be restricted in light of the limited nature of the review procedures applied.

The liability of PricewaterhouseCoopers, in relation to the performance of their professional services provided to Karoon Energy Limited including, without limitation, PricewaterhouseCoopers's audits and reviews of Karoon Energy Limited's financial statements described above, is limited under the Chartered Accountants Australia and New Zealand Scheme (NSW) (the "Accountants Scheme") approved by the New South Wales Professional Standards Council or such other applicable scheme approved pursuant to the Professional Standards Act 1994 (NSW) (the "Professional Standards Act"). Specifically, the Accountants Scheme limits the liability of PricewaterhouseCoopers to a maximum amount of A$75 million for audit work and A$20 million for other work. The Accountants Scheme does not limit liability for breach of trust, fraud or dishonesty. These limitations of liability may limit enforcement in Australian court of any judgment under United States or other foreign laws rendered against PricewaterhouseCoopers based on, or related to, its audit of the financial statements of Karoon Energy Limited. The Accountants Scheme commenced on October 8, 2019 and will remain in force for a period of five years (unless it is revoked, extended or ceases in accordance with the Professional Standards Act). The Professional Standards Act and the Accountants Scheme have not been subject to relevant judicial consideration and, therefore, how the limitations will be applied by courts and the effect of the limitations on the enforcement of foreign judgments is untested.

PricewaterhouseCoopers' registered address is 2 Riverside Quay, Southbank VIC 3006, Australia.

The audited statements of revenues and direct operating expenses of the Who Dat assets for each of the two years in the period ended December 31, 2023 and included in this offering memorandum have been audited by Ernst & Young LLP, independent auditors, as stated in their report appearing herein.

Ernst & Young LLP's registered address is 3900 Hancock Whitney Center, 701 Poydras Street, New Orleans, Louisiana 70139.

Admission to Trading and Listing

We intend to apply for the listing and quotation of the Notes on the SGX-ST. The SGX-ST assumes no responsibility for the correctness of any of the statements made or opinions or reports contained in this offering memorandum. Admission of the Notes to the Official List of the SGX-ST, and the listing and quotation of the Notes on the Official List of the SGX-ST, are not to be taken as an indication of the merits of the Issuer, the Guarantors, our subsidiaries, our associated companies, the Notes or the Guarantees. The Notes will be traded on the SGX-ST in a minimum board lot size of S$200,000 (or its equivalent in foreign currencies) for as long as any of the Notes are listed on the SGX-ST and the rules of the SGX-ST so require.

Upon any issuance of definitive notes, the Issuer will appoint and maintain a paying agent in Singapore for so long as the Notes are listed on the SGX-ST and the rules of such exchange so require. In such event, an announcement shall be made through the SGX-ST and will include all material information with respect to the delivery of the definitive notes, including details of the paying agent in Singapore.

Approval

The Issuer and the Guarantors will obtain all necessary consents, approvals, authorizations or other orders for the issuance of the Notes and the Guarantees and the other documents to be entered into by the Issuer and the Guarantors in connection with the issuance of the Notes.

Clearing Information

Notes sold in the United States in reliance on Rule 144A will be evidenced by Notes in global form called “Restricted Global Notes,” which will be deposited with a custodian for, and registered in the name of a nominee of, DTC. Notes sold outside the United States in reliance on Regulation S will be evidenced by a separate Note in global form called a “Regulation S Global Note,” which also will be deposited with a custodian for, and registered in the name of a nominee of, DTC for the accounts of Euroclear and Clearstream.

ANNEX A – SUMMARIES OF INDEPENDENT RESERVE REPORTS

Ref: 3338 Karoon CPR

18. March 2024

Mr. Martin Austgulen

Karoon Energy

Av. República do Chile, 330 – 5º andar

Torres Oeste, Rio de Janeiro, Brazil

Subject: Reserves and future revenue of Karoon's interests in BM-S-40, Brazil

Dear Mr. Austgulen:

In accordance with your request, we have estimated the contingent resources, proved, probable, and possible reserves and future revenue, as of December 31, 2023, to the Karoon Energy (Karoon) interest in three producing fields in the BM-S-40 Concession in Brazil. We completed our evaluation on February 28th, 2024. The estimates in this letter have been prepared in accordance with the guidelines of the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE issued in 2018. The main definitions are presented immediately following this letter. We estimate the net reserves and future net revenue from oil and gas extraction activities to the Karoon interest in these properties, as of December 31, 2023, to be:

	Net Reserves			Future net revenue[1] (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present worth at 10%
Proved Developed Producing	30,135.6	-	-	696,060.4	736,134.3
Proved Developed Non-Producing	3,341.9	-	-	179,466.3	148,760.1
Proved Undeveloped	-	-	-	-	-
Total Proved (1P)	33,477.5	-	-	875,526.7	884,894.4
Probable	11,864.2	-	-	494,361.8	413,291.0
Proved + Probable (2P)	45,341.7	-	-	1,369,888.4	1,298,185.5
Possible	9,603.4	-	-	612,007.1	456,145.0
Proved + Probable + Possible (3P)	54,945.1	-	-	1,981,895.5	1,754,330.4

Totals may not add because of rounding

(1) Future net revenue is after deducting estimated opex, capex and abandonment costs.

In addition, we estimate the net contingent resources from oil and gas extraction activities to the Karoon interest in these properties, as of December 31, 2023, to be:

	Net Contingent Resources (Develoment Pending)		
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)
Low estimate, 1C (C1)	7,842.6	-	-
Best estimate, 2C (C1+C2)	11,190.5	-	-
High estimate, 3C (C1+C2+C3)	16,192.4	-	-

These volumes are contingent upon extending the field life from end of 2032 to end of 2038.

The oil volumes shown include crude oil and condensate and are expressed in thousands of barrels (MBBL). No sales NGL nor Gas volumes are reported. Reserves categorization conveys the relative degree of certainty. Reserves sub-categorization is based on development and production status. The estimates of reserves and resources and the future revenue included herein have not been adjusted for risk.

Future net revenue is Karoon's share of the gross (100 percent) revenue from the properties after deductions for Karoon's share of royalties, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. Future net revenues are expressed in thousand US dollars (M$). Future net revenue presented in this letter, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this letter are based on Brent forward curve for the first three years, i.e. to year end 2026, and Brent long term $65 per barrel (real 2021) + 2% inflation p.a. for the remaining field life. The sales prices for the oil are quality-adjusted by -$3.26 USD per barrel towards Brent prices. This is based on historically achieved sales as instructed by Karoon. The applied oil prices are:

	Units	2024	2025	2026	2026 - EOFL
Oil Price	USD/bbl (real2024)	77.69	71.72	67.32	65.72

The operating costs used in this letter are based on operating expense records of Karoon. These costs encompass overhead expenses allowed under joint operating agreements. The breakdown of these costs includes production unit costs, logistics, HSE, labour, chemicals, insurance and work-over costs. The predominant component of the operating cost is the daily rate for both charter and service contracts. Karoon’s general and administrative overhead expenses at the headquarters are included to the extent that they are covered under joint operating agreements for the operated properties. The costs provided are considered realistic and reasonable, given the present market conditions and field experience costs.

The capital costs used in this letter were supplied by Karoon and are based on authorizations for expenditure and real expenses incurred in recent projects. These capital costs encompass necessary provisions for activities such as workovers, life extension work, measuring improvements and uptime efficiency improvements. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. The abandonment costs used in this letter represent Karoon's estimates of the expenses associated with abandonment of the wells, platforms, and production facilities, net of any salvage value.

For the purposes of this letter, we did not perform any field inspection of the properties, nor did we examine the mechanical functionality or state of the wells and facilities. Moreover, we did not investigate possible environmental liabilities related to the properties. Consequently, our estimates exclude any costs due to such potential liabilities.

We have made no investigation of potential volume and value imbalances resulting from over- or under-delivery to the Karoon interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Karoon receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

The reserves presented in this letter are estimates only and should not be interpreted as exact quantities. Proved reserves refer to quantities of oil which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible. Probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease due to changes in market conditions, future operations, changes in regulations, or actual reservoir performance.

In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Karoon, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are successfully recovered, the resulting revenues and associated costs could be more or less than the estimated amounts.

For the purposes of this letter, we employed technical and economic data encompassing, but not restricted to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. Our approach involved the utilization of standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogies, that we consider to be appropriate and necessary to categorize and estimate reserves in accordance with PRMS definitions and guidelines. Given the inherent uncertainties in the interpretation of engineering and geoscience data in the field of oil and gas evaluation, our conclusions necessarily reflect only informed professional judgment.

The data used in our estimates were obtained from Karoon, public data sources, and the nonconfidential files of AGR, has been validated as accurate. Verification of property titles or independent confirmation of the specific degree or type of ownership interest has not been undertaken. The technical personnel responsible for the estimates presented herein adhere to the qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. These individuals, comprising independent petroleum engineers, geologists, geophysicists, and petrophysicists, neither possess interest in the properties nor are they engaged on a contingent basis.

Project manager for the study was Gudmund Olsen (MSc in Petroleum Engineering), AGR Reservoir Engineering Manager. Mr. Olsen, a Reservoir Engineer, has 30+ years of international and Norway experience. The letter was reviewed by Anna-Lena Hellmann, (MSc Petroleum Exploration). Ms. Hellman has 30+ years of experience as a exploration and reservoir geologist. The letter was signed off by Erik Lorange (MSc in Applied Geophysics), AGR Vice President Reservoir Management. Mr. Lorange, has 30+ years of international and NCS experience.

Yours Sincerely,

Erik Lorange

Summary of 2018 SPE Petroleum Resources Management System

The following tables have paragraphs that are quoted from the 2018 Petroleum Resources Management System (PRMS) and summarise the key resources classes and categories, while the figure below shows the recommended sub-classes based on project maturity.

Summary of 2018 Petroleum Resources Management System – Recoverable Resources Classes and Sub-Classes

Class/Sub-class	**Definition**
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.
On Production	The development project is currently producing and selling petroleum to market.
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.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of lettering, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
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 due to one or more contingencies.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
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.
Development Unclarified	A discovered accumulation where project activities are under assessment and where justification as a commercial development is unknown based on available information.
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.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

Summary of 2018 Petroleum Resources Management System – Reserves Status Definitions	
Status	**Definition**
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.

Summary of 2018 Petroleum Resources Management System – Reserves Categories Definitions	
Category	**Definition**
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.
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.
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.

Summary of 2018 Petroleum Resources Management System – Contingent Resources	
Category	**Definition**
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.

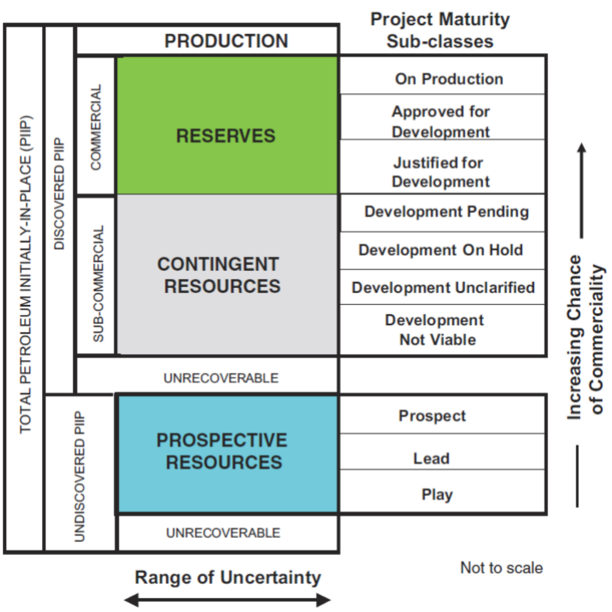


Figure 1 - Illustration of the SPE's Reserves classification system (Source: www.spe.org)

ESTIMATES

of

RESERVES AND FUTURE REVENUE
AND CONTINGENT RESOURCES

to the

KAROON ENERGY LTD INTEREST

in

CERTAIN OIL AND GAS PROPERTIES

located in

DOME PATROL AND WHO DAT FIELDS
FEDERAL WATERS IN THE GULF OF MEXICO

as of

DECEMBER 31, 2023

BASED ON ESCALATED PRICE AND COST PARAMETERS

specified by

KAROON ENERGY LTD

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

April 9, 2024

Mr. Martin Austgulen
Karoon Energy Ltd
Level 3/6 Riverside Quay
Southbank VIC 3006
Australia

Dear Mr. Austgulen:

In accordance with your request, we have estimated the proved, probable, and possible reserves and future revenue, as of December 31, 2023, to the Karoon Energy Ltd (KAR) interest in certain oil and gas properties located in Dome Patrol and Who Dat Fields, federal waters in the Gulf of Mexico. Also as requested, we have estimated the contingent resources, as of December 31, 2023, to the KAR interest in the Who Dat East Discovery. We completed our evaluation on or about February 27, 2024. This report has been prepared using escalated price and cost parameters specified by KAR, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the net reserves and future net revenue to the KAR interest in these properties, as of December 31, 2023, to be:

	Net Reserves			Future Net Revenue[(1)] (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	5,353.7	209.8	9,827.8	179,650.1	188,140.6
Proved Developed Non-Producing	4,003.7	83.7	3,921.3	263,184.5	193,707.6
Proved Undeveloped	4,208.8	499.6	23,409.7	197,498.2	132,252.7
Total Proved (1P)	13,566.3	793.1	37,158.8	640,332.7	514,100.9

Category	Net Reserves Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Future Net Revenue[(1)] (M$) Total	Present Worth at 10%
Probable	5,801.0	506.3	23,724.7	395,845.1	262,692.3
Proved + Probable (2P)	19,367.3	1,299.4	60,883.5	1,036,177.8	776,793.3
Possible	9,639.0	393.1	18,420.7	625,480.5	318,033.4
Proved + Probable + Possible (3P)	29,006.2	1,692.6	79,304.2	1,661,658.3	1,094,826.7

Totals may not add because of rounding.

(1) Future net revenue is after deducting estimated abandonment costs.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue for the reserves is KAR's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for KAR's share of capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using oil, NGL, and gas price parameters specified by KAR. Oil and NGL prices are based on NYMEX West Texas Intermediate prices and are adjusted for quality, transportation fees, and market differentials. Gas prices are based on NYMEX Henry Hub prices and are adjusted for energy content, transportation fees, and market differentials. All prices, before adjustments, along with escalation parameters are shown in the following table:

Period Ending	Oil/NGL Price ($/Barrel)	Gas Price ($/MMBTU)
12-31-2024	75.14	2.25
12-31-2025	70.58	3.23
12-31-2026	67.20	3.59

Thereafter, escalated 2 percent on
January 1 of each year.

Operating costs used in this report are based on operating expense records of LLOG Exploration Offshore, LLC (LEO), the operator of the properties. These costs include production handling agreement (PHA) fees, the per-well overhead expenses allowed under joint operating agreements, and other estimates of costs to be incurred at and below the district and field levels. Operating costs used in this report have been reduced by expenditure reimbursements, as allowed under the PHAs. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Headquarters general and administrative overhead expenses of LEO are included to the extent that they are covered under joint operating agreements. As requested, operating costs are held constant through December 31, 2024, and then escalated 2 percent on January 1 of each year throughout the remaining lives of the properties.

Capital costs used in this report were provided by LEO and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of LEO's future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are LEO's estimates of the costs to abandon the wells, platform, and production facilities, net of any salvage value. As requested, capital costs and abandonment costs are held constant through December 31, 2024, and then escalated 2 percent on January 1 of each year to the date of expenditure.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the KAR interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on KAR receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in LEO's historical field- and lease-level accounting statements.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are for the Who Dat East Discovery (Mississippi Canyon Blocks 464, 465, 508, and 509). This discovery has been penetrated by the MC509 1 well. These resources are contingent upon approval of a development plan and commitment to develop the resources. Because of the early stage of development of this project, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. The project maturity subclass for these contingent resources is development unclarified.

We estimate the gross (100 percent) contingent resources for the Who Dat East Discovery by reservoir, as of December 31, 2023, to be:

	Gross (100%) Contingent Resources					
	Oil (MBBL)			Gas (MMCF)		
Reservoir	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
M57B	511.6	1,449.5	4,421.6	7,308.2	15,258.2	31,582.7
M57C	524.8	2,398.8	10,660.5	7,497.3	25,250.0	76,146.2
M56	390.9	954.3	2,644.2	5,583.9	10,044.9	18,887.3
M48	553.4	1,453.3	3,495.8	7,905.0	15,298.3	24,970.2

We estimate the net contingent resources to the KAR interest in the Who Dat East Discovery by reservoir, as of December 31, 2023, to be:

	Net Contingent Resources					
	Oil (MBBL)			Gas[(1)] (MMCF)		
Reservoir	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
M57B	163.0	461.8	1,408.6	2,328.1	4,860.7	10,061.2
M57C	167.2	764.2	3,396.1	2,388.4	8,043.8	24,257.5
M56	124.5	304.0	842.4	1,778.8	3,199.9	6,016.8
M48	176.3	463.0	1,113.7	2,518.3	4,873.5	7,954.6

(1) Net gas volumes are prior to deductions for shrinkage.

The oil volumes shown include condensate only.

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. The estimates of contingent resources included herein have not been adjusted for development risk.

GENERAL INFORMATION

This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves and contingent resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by LEO, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves and contingent resources in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. A substantial portion of the reserves shown in this report are for behind-pipe zones, non-producing zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based, and the contingent resources shown in this report are for

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undeveloped locations. Such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from KAR, LEO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: Lee E. George
Lee E. George, P.E. 95018
Vice President

Date Signed: April 9, 2024

STATE OF TEXAS
L. E. GEORGE
95018
LICENSED
PROFESSIONAL ENGINEER

By: Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

Date Signed: April 9, 2024

STATE OF TEXAS
E. C. ROY, III
GEOLOGY
2364
LICENSED
PROFESSIONAL GEOSCIENTIST

LEG:LAZ

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Resources.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

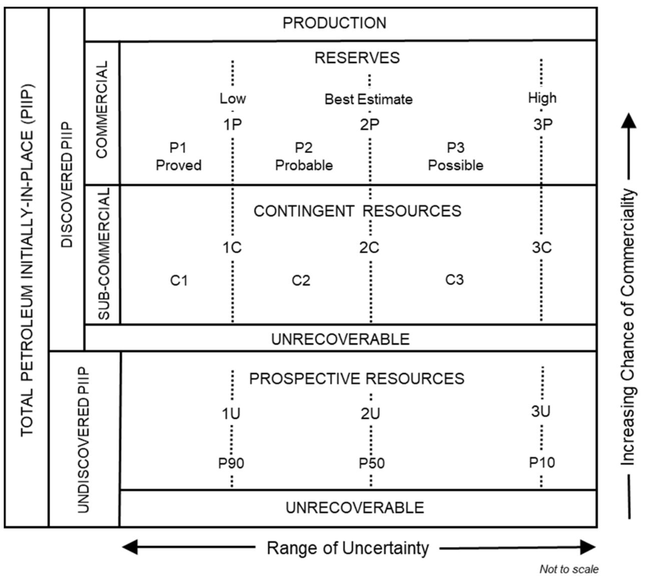

Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. 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 range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, 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 because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

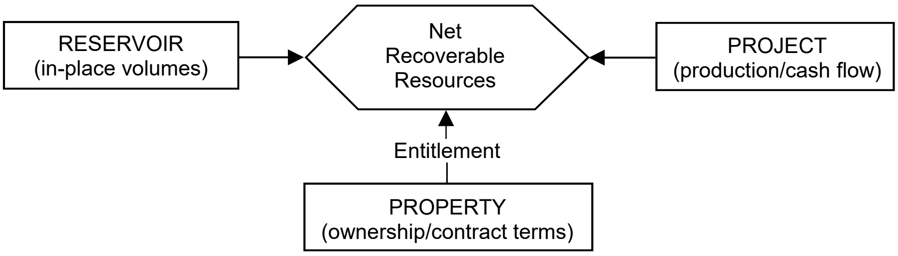

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and 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 justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3) reserves; 1C, 2C, 3C, C1, C2, and C3 contingent resources; or 1U, 2U, and 3U prospective resources categories. The chance of commerciality is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS
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2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.
2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	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.
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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Class/Sub-Class	Definition	Guidelines
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.
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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Class/Sub-Class	Definition	Guidelines
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 commercial 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.
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—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.

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Status	Definition	Guidelines
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—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. 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.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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Category	Definition	Guidelines
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.

ANNEX B – BRAZIL AND US GULF OF MEXICO OFFSHORE MARKET ASSESSMENT

April 2024

Karoon Energy Brazil and US Gulf of Mexico Offshore Market Assessment

Wood Mackenzie Consulting

Strictly Private and Confidential

Wood Mackenzie (also referred to as “Woodmac” in this report) has prepared this report (the “Report”) which provides our independent view of global supply and demand for oil and gas and in-depth overviews and assessments of select producing regions.

The Report is intended solely for the benefit of the client (Karoon Energy or “Karoon”) and the Debt Financing Parties underwriting the proposed debt offering, and may not be relied upon by any other party without Wood Mackenzie’s prior written consent.

The information upon which this Independent Report is based has either been supplied to us by Karoon, or comes from our own experience, knowledge, and databases. The opinions expressed in this report are those of Woodmac. They have been arrived at following careful consideration and enquiry, but we do not guarantee their fairness, completeness, or accuracy.

This Report does not represent any form of technical or legal due diligence. Potential investors should note that in preparing this Report we have relied on certain pieces of technical and operational information provided to us by Karoon

This report was prepared at and reflects research and analysis made known to Woodmac as of March 1, 2024, and cannot be regarded as reporting as of any subsequent date. The opinions, which are presented as of this date, are subject to change.

Table of Contents

1. Executive Summary

Woodmac prepared the following Independent Market Consultant Report to accompany Karoon's 144A / Reg S bond offering. This report supplements Karoon's existing asset base by providing information and analysis regarding the two offshore markets where Karoon produces oil and gas: offshore Brazil and the US Gulf of Mexico (US GoM). The report is structured to provide potential investors with additional background and understanding of these markets. The report builds on Woodmac's existing research base and our own proprietary knowledge of these markets.

The report is structured to provide a macro overview of supply and demand, as well as an assessment of the global offshore oil and gas to establish the role each focus region plays in the broader offshore market. The offshore market overview establishes the necessary context for more detailed overviews and analysis on both Brazil offshore and the US GoM.

Karoon expanded its upstream asset portfolio in Q4 2023 by acquiring a 30% stake in two producing deepwater GoM fields: Who Dat and Dome Patrol. The acquisition also includes interests in associated infrastructure and several surrounding exploration blocks. Entry into deepwater GoM diversifies Karoon's existing asset base to a second core offshore market. Karoon also holds operated interests in the mature producing Bauna FPSO project, with three connected oil fields, plus two nearby oil discoveries, Neon and Goia, currently being studied for development feasibility.

Karoon's Brazilian assets are in water depths ranging from ~230-315 metres. The assets are considered shallow water with water depths less than 400 metres; however, the water is deep enough to require development concepts comparable to deepwater operations. The Bauna FPSO project holds similarities to other deepwater FPSO developments across Brazil.

Karoon strategically positioned its asset base in two advantaged oil basins characterized by resource scale, production history, established service sectors and associated supply chains, and existing infrastructure. Brazil and US GoM represent two of the most active and proven offshore oil and gas markets globally. Each region provides relatively stable operating environments and possesses numerous attributes that support and encourage ongoing capital investment.

- Brazil is the largest offshore liquids producer globally, while the US is the fifth largest. Collectively, the two countries are expected to account for approximately 21% of total offshore liquids production in 2024
  Brazil and the US are the two largest deepwater liquids producers globally, combining for 67% of all forecasted 2024 deepwater liquids production
- Since 2000, Brazil and the US GoM yielded more offshore liquids resource discoveries than any other country
- The only countries with more remaining offshore liquids resources are OPEC or former OPEC members
- Since 2015 the two markets account for 31% of all exploration and appraisal (E&A) wells drilled globally and 30% of sanctioned projects with commercial reserves greater than 50 million barrels of oil equivalent (Boe)
- US GoM and Brazil collectively possess 31% of total operational production platforms globally; this also includes 40% of all floating production facilities comparable to Karoon's platform concepts
- 42% of contracted floating rigs are operating in the two markets
- Each region is supported by an established supply chain and service sector that enables the scale of operations
- Large, well-capitalized, globally diversified oil and gas producers continue to produce and invest in each region

Brazil possesses a number of additional attributes that highlight the scale of the sector. In addition to serving as the world's leading market for offshore floating drilling rigs, it is also the most active market globally in terms of FPSO (Floating, Production, Storage, and Offloading) and SURF (Subsea, Umbilicals, Risers and Flowlines) installations.

The size of the resource base and associated supply chain underscore the sector's overall importance to the Brazilian economy in terms of tax revenue, employment, and foreign investment. Upstream oil and gas royalties and taxes contributed 8% of 2023 government tax revenue, and the overall oil and gas sector is estimated to make up 10% of Brazil's GDP[1]. Brazil's concessionary fiscal terms, applicable to mature fields (including Karoon's Bauna asset), also

[1] Sources: Brazil Federal Revenue Service, World Bank, US International Trade Association

contain lower graduated royalty rates[2], demonstrating policies to encourage ongoing investment and development of mature fields.

Deepwater US GoM also possesses a number of distinct attributes that combine to make it an advantaged oil basin. These factors coalesce to make produced barrels in the US GoM among the most valuable barrels globally on an net present value (NPV) per barrel basis at a long-term economic assumption of US$65/bbl Brent (real 2024 terms).

- A stable concessionary fiscal regime with a competitive 18.75% flat royalty rate (note that current royalties for new licenses are set at 18.75%; however, Woodmac assumes a 12.5% applicable royalty for Who Dat based on the timing of the lease award while Dome Patrol is set at 18.75%)
- Established infrastructure, including an expansive network of offshore pipelines (20% of offshore pipelines globally), direct access to one of the world's most concentrated refining centers, and industrial demand across the US Gulf Coast
- Quicker and more cost-efficient development opportunities via infrastructure-led exploration (ILX)
- Low-point forward breakevens for remaining resources (lowest deepwater breakeven globally and trailing only Middle East onshore and Middle East shallow water)
- Among the lowest Scope 1 and Scope 2 emissions intensity out of any region or resource theme globally

These attributes combine combine to create advantaged asset profiles, and each region plays an important role in the overall trajectory for oil and gas production. Woodmac identifies a 23 million barrel per day liquids supply gap by 2035 that takes into account onstream production declines and visible developments (both approved and probable developments). Addressing the supply gap requires ongoing investment in exploration and reserves growth to meet global demand in the future.

As producers focus on portfolio rationalization and continued investment amid a gradual energy transition, the most advantaged assets will best compete for the capital necessary to fill that gap. Offshore Brazil and the US GoM possess many of the attributes that producers will prioritize: resource scale, competitive point forward breakevens, relative fiscal stability, and low emissions intensity.

[2] Source: Karoon Energy

2. Global Offshore Oil and Gas Market Overview & Forecasts

Karoon's December 2023 acquisition of deepwater oil and gas interests in the US GoM added diversification to its Brazil-focused offshore business. Karoon's portfolio now consists of offshore interests in two advantaged, oil-rich provinces. Both regions prominently contribute to the overall global offshore oil and gas industry.

Section 2 summarizes the offshore landscape globally, framing Brazil and the US GoM's standing within the broader offshore sector. Sections 3 & 4 subsequently address each individual market in greater depth.

2.1. Wood Mackenzie Base Case

Woodmac develops long-term outlooks for global oil and gas supply and demand, which are then used as the basis for associated commodity price forecasts. Long-term outlooks are updated semi-annually. The outlook being used in this report is the October 2023 Investment Horizon Outlook (IHO). As such, 2H 2023 forward represents the forecasted period.

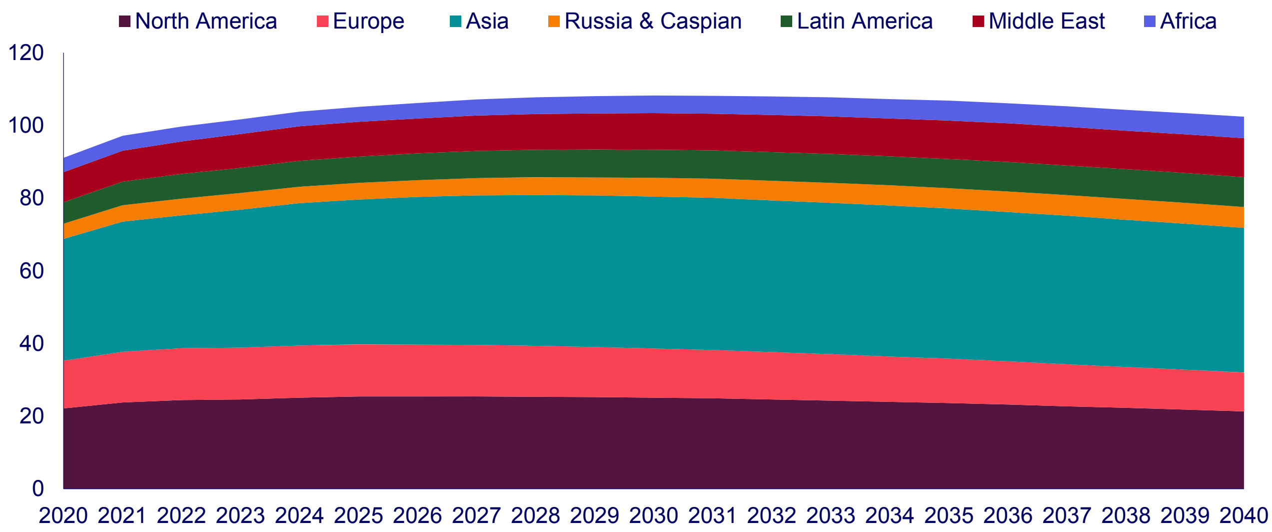
Woodmac's base case IHO represents our energy transition outlook, reflecting a transition scenario consistent with a 2.5°C global warming scenario by the end of this century (from pre-industrial temperatures). It is our estimation of the most likely outcome, not alignment with a 1.5°C warming scenario as targeted by the 2015 Paris Agreement. The energy transition scenario is based on the evolutions of current policies and the steady advancement of current and nascent low-carbon technologies and solutions.

2.1.1. Liquids Forecasts

This section sets forth Woodmac's forecasts and expectations for global liquids demand and supply through 2040.

Global Liquids Demand by Region, 2020-2040

Millions of barrels per day

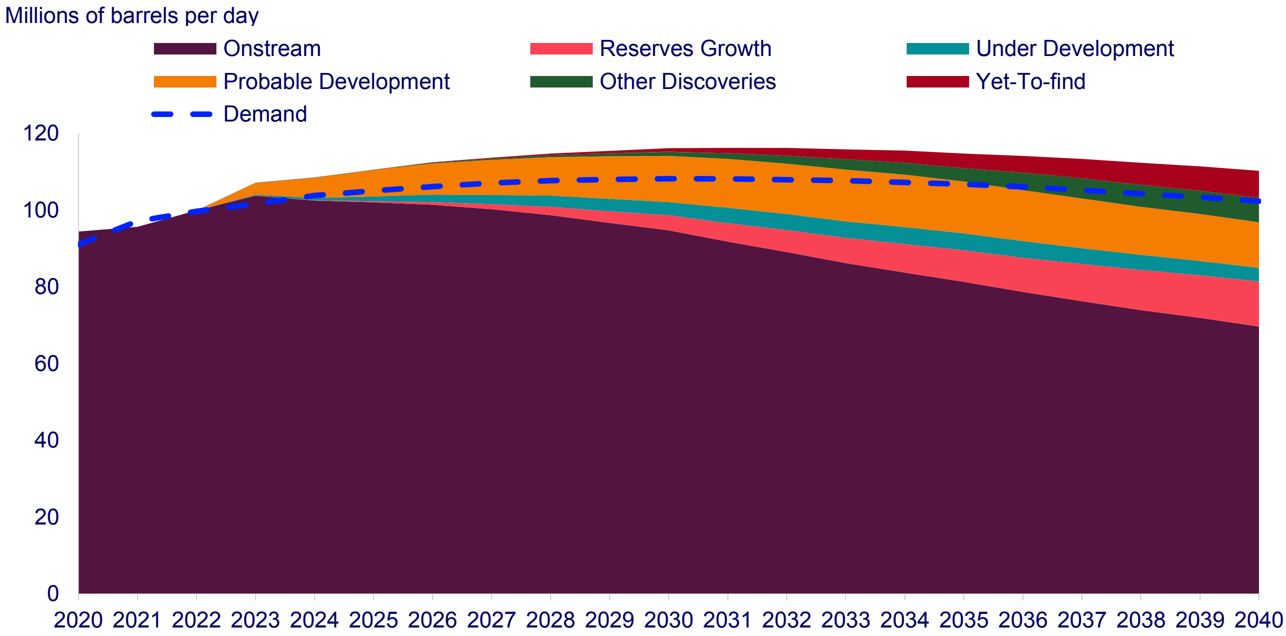


Source: Wood Mackenzie: Macro Oils Investment Horizon Outlook (2H 2023); Note: 2H 2023 onward represents the forecasted period in the 2H 2023 Investment Horizon Outlook used

Global liquids demand increases from 101.7 million barrels per day in 2023 to 106.8 million barrels per day by 2035. Total demand peaks at 108.2 million barrels per day by 2030. Overall demand trajectories demonstrate regional divergences based on differing economic conditions and energy transition objectives. Demand in OECD countries declines faster with more advanced transition goals, while many emerging economies see continued demand growth into the 2040s.

Steady growth in transport electrification leads to lower demand for road fuels. Demand for gasoline peaks by 2027 as fuel demand for light passenger vehicles is pressured by a growing share of EV sales. Road freight and shipping fuel demand does not decline as quickly but follows a similar trend. Aviation fuels exhibit the most resilience among transportation fuels. In contrast to transportation fuels, petrochemical feedstock demand continues to grow throughout the middle of the next decade.

Global Liquids Supply by Development Status, 2020-2040



Source: Wood Mackenzie; Macro Oils Investment Horizon Outlook (2H 2023), Oil Supply Tool; Note: 2H 2023 onward represents the forecasted period in the 2H 2023 Investment Horizon Outlook used

Woodmac's liquids supply forecast reflects global production capacity. The starting point for hydrocarbon liquids analysis is a detailed picture of the supply generated by a build-up from our field-by-field upstream asset valuations. These projects reflect onstream, under development, and probable developments. Additional adjustments are made for anticipated reserve growth, other discoveries, and yet-to-find volumes. For OPEC countries, the forecast is made for production capacity rather than expected production.

Global liquids production capacity peaks at 116 million barrels per day from 2030-2032 before entering a gradual long-term decline. The 116 million barrel per day peak is an increase of 8% over 2023 capacity of 107 million barrels per day. Onstream production declines contribute to the gradual post-peak decline, with onstream production falling by 32% from 2024-2040.

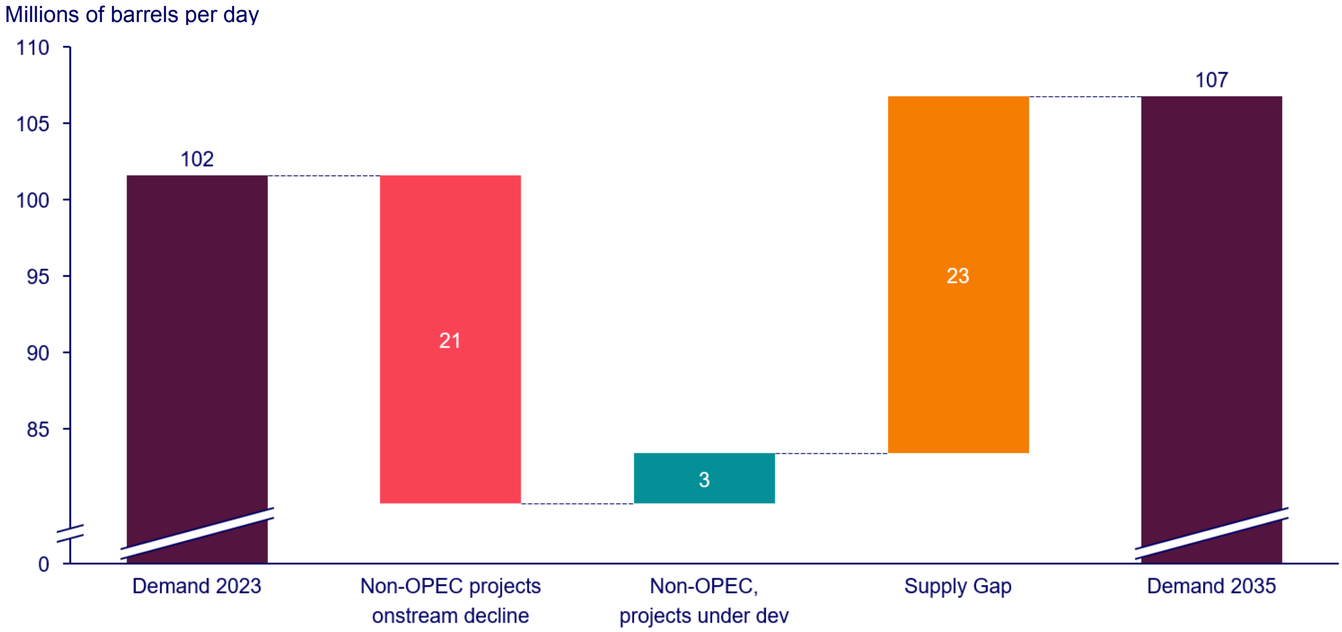
Supply outlooks for OPEC countries are made on the basis of production capacity rather than expected production. The reason for this is to keep an independent view of supply based on capacity rather than forecasting an output level intended to help balance the market. This approach keeps supply and demand forecasts independent of each other. OPEC is expected to continue to add capacity throughout the remainder of the decade, led by planned capacity additions in Saudi Arabia and the UAE.

Overall OPEC crude capacity grows steadily from 34 million barrels per day in 2023 to over 37 million barrels per day in 2035. OPEC crude accounts for 32% of global liquids capacity through the forecasted period. Total capacity of over 37 million barrels a day maintains a prolonged plateau from 2031 to 2048. Overall, OPEC spare capacity averages 7.5 million barrels per day from 2024-2040.

US Lower 48 onshore drives near-term non-OPEC growth. Short-cycle unconventional tight oil production in the US has contributed to nearly 5 million barrels per day of liquids supply growth over the past 10 years. The pace of growth slows down, but US Lower 48 still projects to add another 1.2 million barrels per day of growth by 2031. Core well inventory depletion then begins contributing to production declines after the 2031 peak. After the 2031 peak, US Lower 48 production by 2040 is over 20% below the 2031 peak, representing an annual decline of 2.5%. A further risk to Lower 48 supply is longer-dated second and third-tier inventory that struggles to meet investment hurdles below US$65/bbl.

Deepwater production, particularly in Latin America and West Africa, serves as a key resource theme for growth moving forward. Brazil contributes steady deepwater production growth, supported by several key deepwater projects that have yet to be sanctioned. Rapid growth from the Stabroek block in Guyana also contributes to material deepwater production growth. High-impact deepwater exploration success in Namibia is also likely to be developed and contribute to production growth.

Liquids Supply Gap by 2035



Source: Wood Mackenzie; Macro Oils Investment Horizon Outlook (2H 2023), Oil Supply Tool

By 2035, 23 million barrels per day of new supply must be brought online to offset demand growth and base production declines from onstream assets. Approved for development projects under construction provide visibility on 3 million barrels per day of incremental supply by 2035 to partially offset base production declines. Potential commercial developments and discovered resources that we do not expect to be developed under current cost and price projections would only account for 6 million of the 23 million barrel per day supply gap.

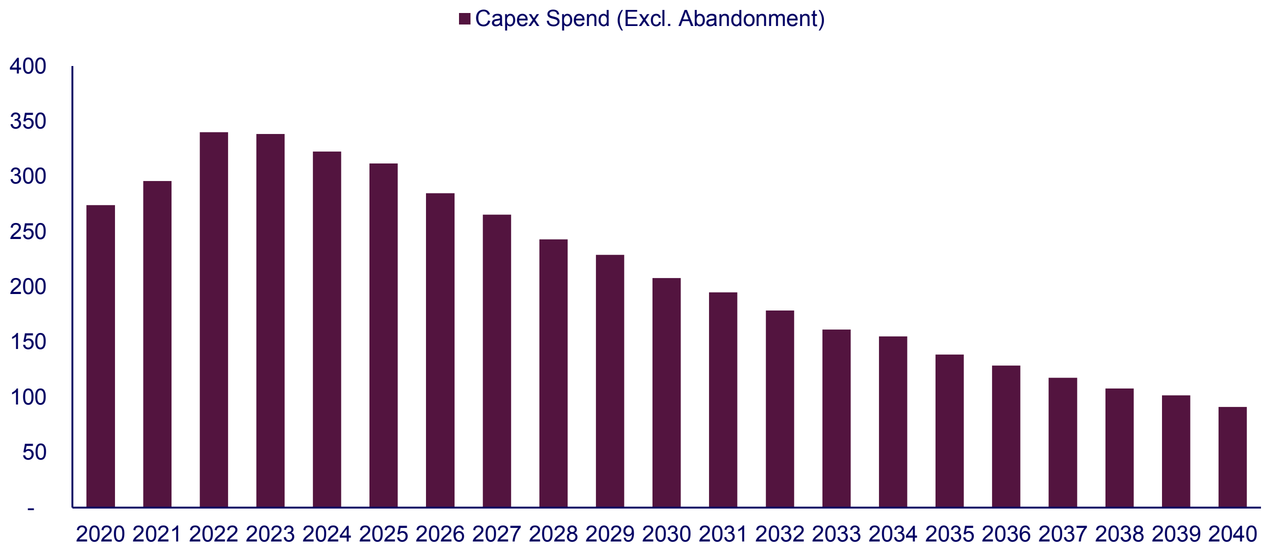
The remaining supply gap needs to be filled with an active upstream industry sanctioning probable developments and continuing to invest in reserves growth and exploration to meet global demand in 2035.

Woodmac's oil supply methodology and supply gap analysis excludes OPEC declines as output from OPEC is dictated more by production quotas than a true decline. Changes in OPEC onstream production over time are not a genuine representation of base decline of an asset, and production increases or declines over time are more the result of managed behavior.

Overall, total onstream production declines by 33% in aggregate from 2023-2040, equal to a compound annual decline rate of 2.3% per year. The modest decline rate for onstream production includes US$3.2 trillion of ongoing capital investment in producing fields. This includes both continued development drilling, future phases for certain projects, and reinvestment in mature fields, among other expenditures. The base decline for those assets deemed onstream represents Woodmac's base forecast of the ongoing commercial development plans for those assets.

Capex Spend (Excl. Abandonment) for Onstream Fields, 2020-2040

US$ Billion (real terms, 2024)

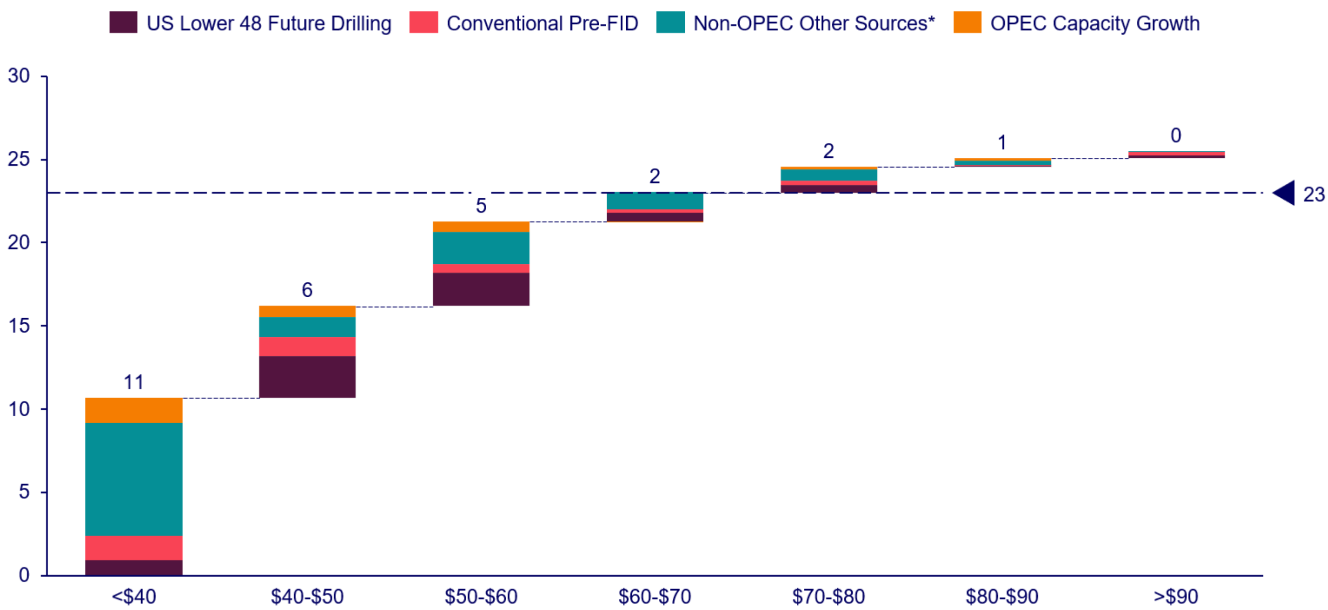


Source: Wood Mackenzie; Lens Upstream, Commercial onstream fields, liquids focused developments (hydro-carbon type is oil or oil and gas)

Capital expenditures, excluding abandonment, for liquids-focused commercial projects that are already onstream, total US$3.2 trillion from 2024-2040. That level of spend indicates that the sector still needs an average annual spend of over US$190 billion simply to manage the 2.3% annual decline for onstream production. That annual average compares to a 2020-2023 average spend of US$325 billion for the onstream fields. The scale of capital to maintain this annual decline also highlights the scale of the incremental capital required to address the forecasted supply gap.

Supply Gap Analysis: Cost of Supply

Millions of barrels per day

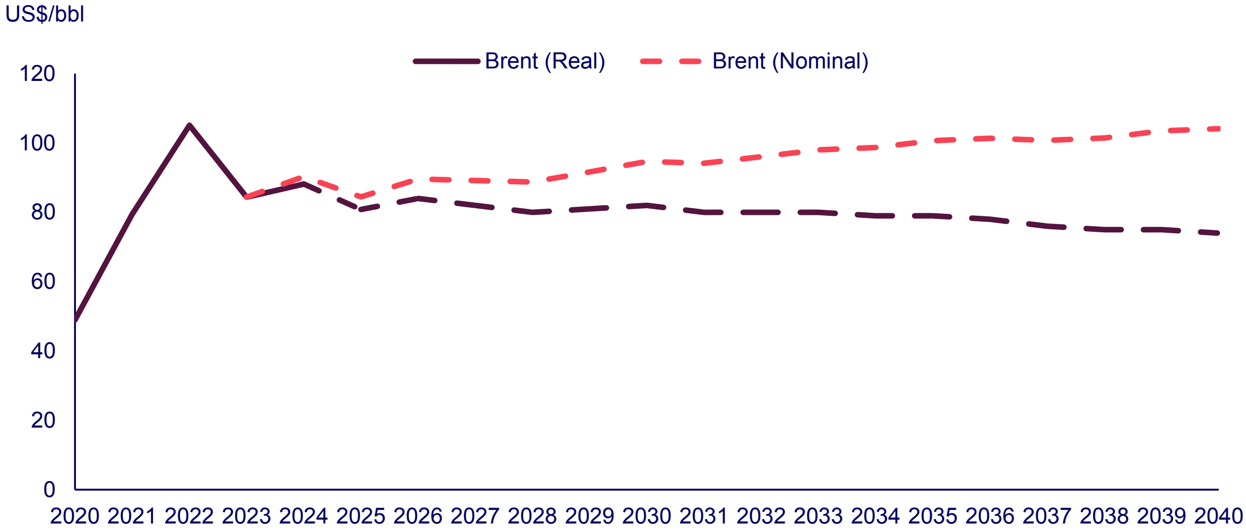


*Source: Wood Mackenzie; Macro Oils Investment Horizon Outlook (2H 2023), Oil Supply Tool; Brent breakeven at a 15% discount rate * Non-OPEC Other Sources: Biofuels, CTL, GTL, Oil Shale, Reserves growth, Yet-to-Find, and Other Technical discoveries*

Woodmac analysis indicates that the breakeven Brent price for the marginal barrel of future supply required to meet the demand outlook is as high as US$70/bbl (real, 2023). The gap is filled by future US tight oil drilling, OPEC capacity growth, conventional pre-FID projects, and other sources. US Lower 48 contributes 6 million barrels per day of production capacity that breaks even under US$60/bbl Brent. Note that is 6 million barrels per day of production capacity to offset current declines, not an incremental 6 million barrels per day of incremental production above current tight oil production. Pre-FID projects contribute 3 million barrels per day that breakeven below US$60/bbl.

Note that the cost of new supply is subject to a 15% discount rate. The discount rate used for the gap analysis and cost of new supply best reflects a market standard and required investment hurdle for sanctioning new resources. This is based on existing methodology and reflects proprietary and primary research.

Brent Price Forecast, 2020-2040



Source: Wood Mackenzie; 2024 real terms, Nominal forecasts reflect 2% annual inflation long-term

Brent oil forecasts range from US$80/bbl to US$84/bbl (real terms, 2023) between 2025-2035. The US$88/bbl projection for 2024 is the highest annual average in the forecast period. Even though demand declines following the 2030 peak, 2035 demand is still higher than current liquids demand. Absolute demand growth coupled with the identified supply gap provides a positive environment for long-term oil prices. Operational risks, geopolitical factors, and investor requirements for free cash flow support the Brent forecast above the US$70/bbl Brent price for the marginal barrels of future supply required to meet the demand outlook .

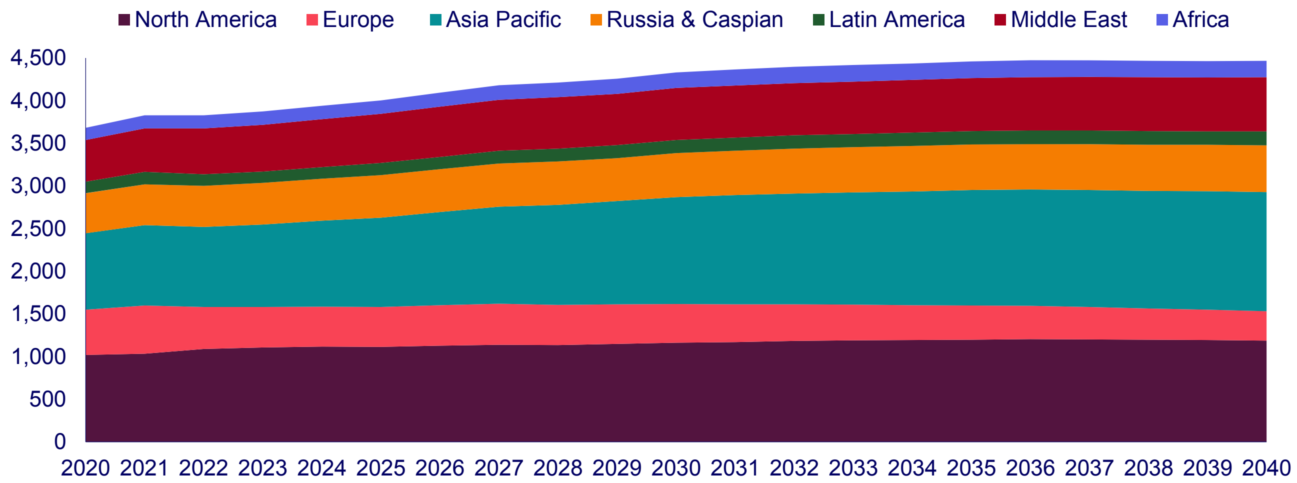
Geopolitical factors, including conflicts and policy approaches, pose risks to base case forecasts. Following Russia's invasion of Ukraine, many governments reassessed energy policies and placed renewed focus on energy security, even at the expense of transition ambitions. Prioritizing energy security offers a tailwind to supply. The Russian and Ukraine war carries additional supply considerations. Russian oil exports have proven resilient despite sanctions, but an end to the conflict and loosening of sanctions earlier than anticipated would act to soften oil prices. An escalation and expansion of conflict in the Middle East that further inhibits oil supply and transportation presents a supply risk in the other direction. An acceleration of energy transition policies and actions would also pressure liquids demand to the downside.

2.1.2. Gas Forecasts

This section sets forth Woodmac's forecasts and expectations for global gas demand and supply through 2040.

Global Gas Demand by Region, 2020-2040

Billion cubic meters (Bcm)

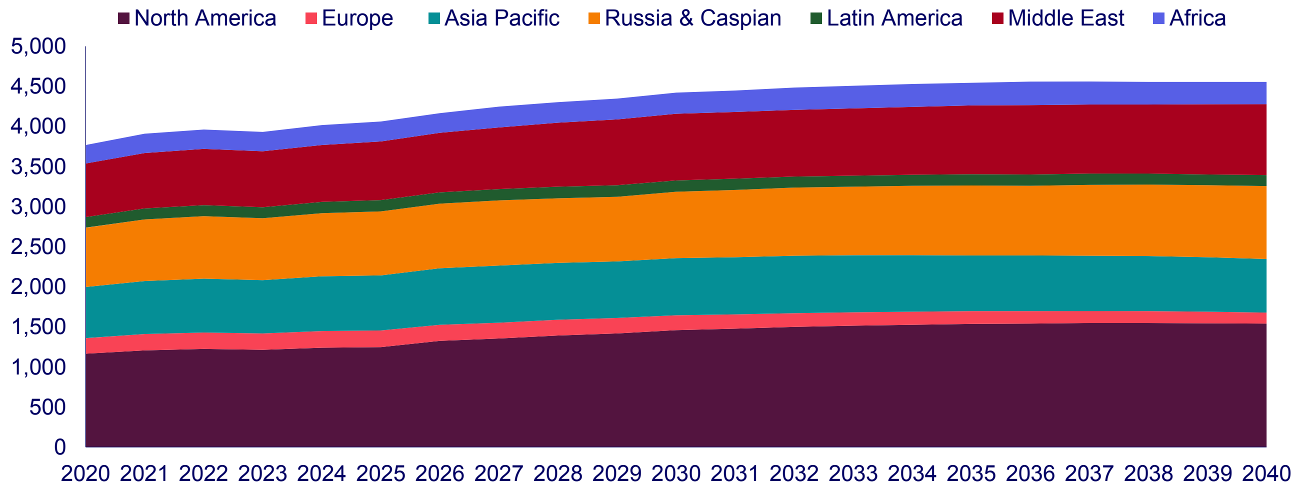


Source: Wood Mackenzie; Global Gas Strategic Planning Outlook

Gas demand demonstrates better resilience through the energy transition relative to liquids. The reason for better overall resilience is gas is considered a transition fuel replacing higher carbon energy sources. Its role as a critical industrial feedstock and alternative to coal aids fuel switching and electrification efforts globally, particularly in Asia. Gas demand peaks in 2037 compared to a liquids peak in 2030. Gas also maintains a longer, flatter post-peak plateau beyond 2040. Gas demand in 2050 is only 4% below the 2037 peak of ~4,500 billion cubic meters.

Global Gas Supply by Region, 2020-2040

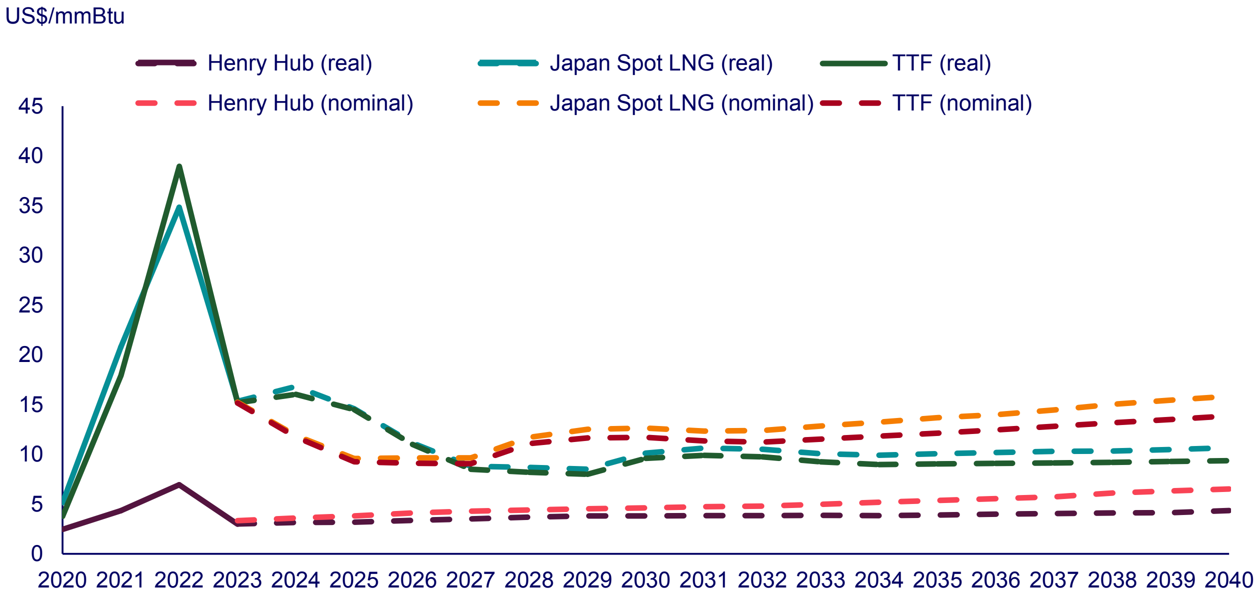
Billion cubic meters (Bcm)



Source: Wood Mackenzie; Global Gas Strategic Planning Outlook

Stable and growing global demand for natural gas drives supply growth in North America. Prolific shale gas basins and associated gas growth from tight oil support a rapid expansion of US LNG capacity. US LNG will ramp up from 78 million metric tonnes per annum in 2022 to more than 200 million metric tonnes per annum by 2033. The LNG build-out provides an outlet for US supply growth while providing international demand centers access to a more reliable gas source.

Global Gas Price Forecasts, 2020-2040



Source: Wood Mackenzie; Global Gas Strategic Planning Outlook

Limited near-term LNG capacity while sanctioned projects take time to come onstream keeps European and Asian prices elevated above long-term forecasts. As LNG capacity comes onstream, the market will rebalance, which will contribute to lower overall price volatility post-2027. Woodmac's gas forecast reflects long-term LNG pricing parity with Henry Hub. Long-term prices will be set by the cost of developing LNG, and US LNG effectively sets the market with other benchmarks reflecting Henry Hub plus the incremental costs for liquefaction and transportation.

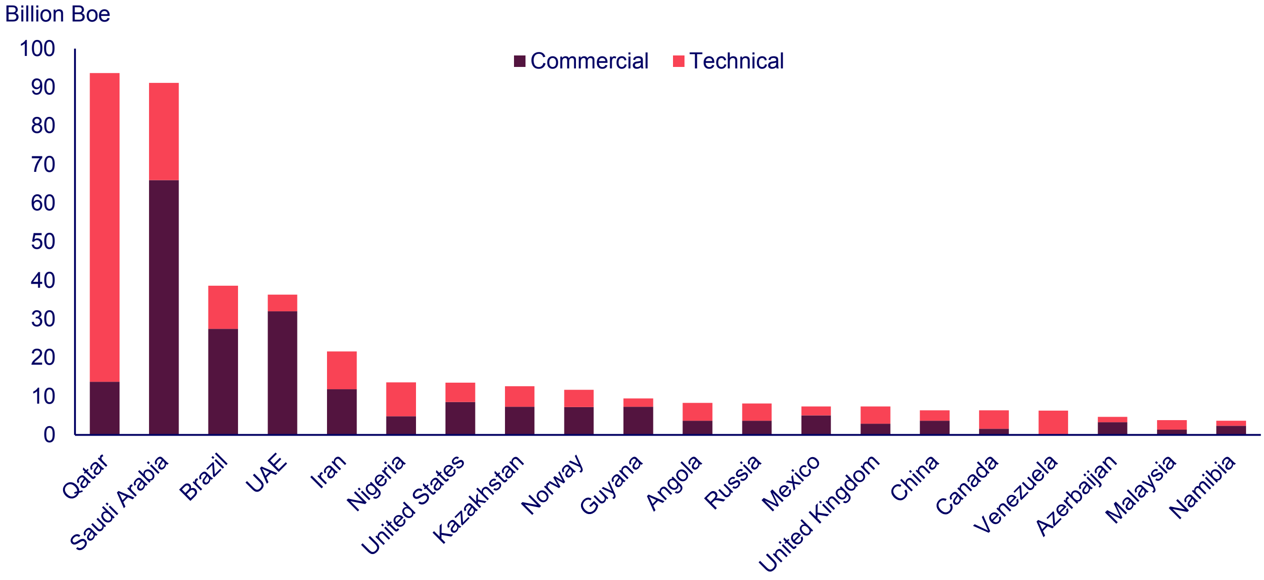
2.2. Global Offshore Reserve Estimates

All subsequent sections for reserves, production, expenses, and government payments represent field-by-field build-ups of Woodmac's global upstream asset database. Data for each project is incorporated into the IHO supply outlook, but the asset level build-up only reflects commercial fields/projects modelled for valuation purposes and will differ from the macro-supply view that also incorporates reserve growth, other discoveries, and yet-to-find volumes.

Commercial reserves represent proved and probable reserves from all fields classified as commercial: a.) fields on production, b.) fields sanctioned and under development (Approved for development), as well as c.) fields expected to be developed. Technical reserves represent contingent resources believed to be present and technically recoverable from the reservoir but are not currently considered commercial.

Woodmac reserve estimates are based on our best estimate view of likely future production. Woodmac does not conduct independent reservoir studies or engineering assessments.

Top 20 Countries by Remaining Offshore Liquids Resources

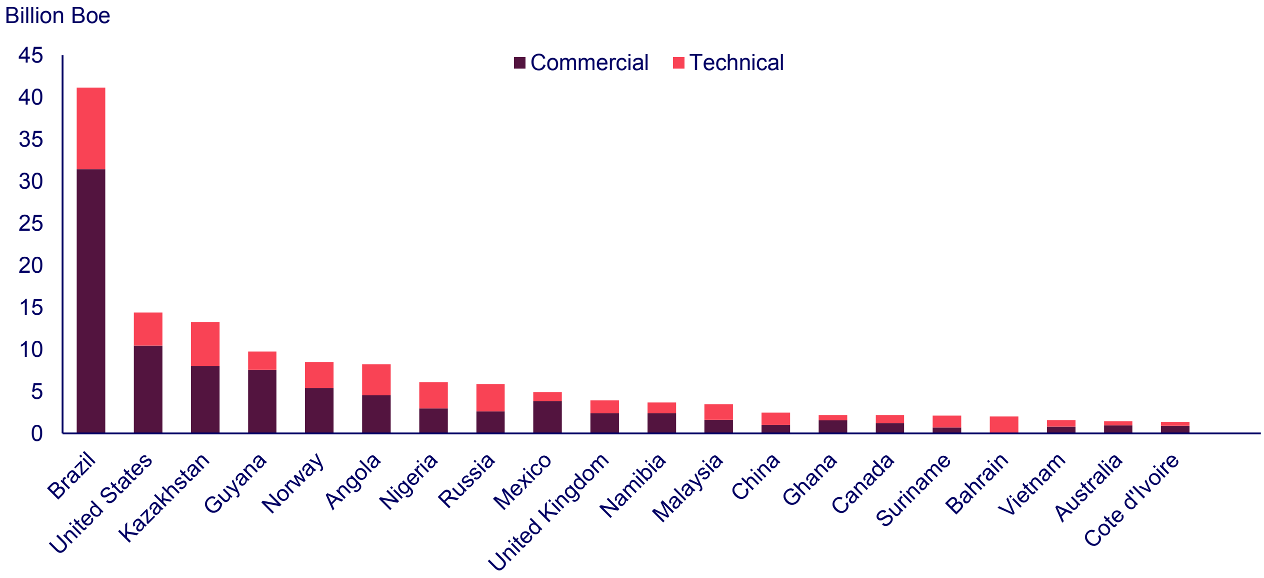


Source: Wood Mackenzie; Remaining offshore resources, all water depths

Brazil and the US GoM's offshore sectors prominently factor into the global marketplace. Only existing or former OPEC members possess more remaining liquids reserves. Virtually all (99.8%) offshore reserves in Qatar, Saudi Arabia, UAE, and Iran are located in shallow water, while reserves in Brazil and the US are weighted towards deepwater.

Among 13.5 billion barrels of remaining offshore liquids resources in the US, 10.3 billion, or 76%, of the resources are in the GoM. 95% of the 38.6 billion barrels of remaining liquids resources offshore in Brazil are located in the Santos and Campos basins. Additionally, the scale of shallow water reserves in the Persian Gulf region has long been established, while the overall prospectivity of the US GoM and Brazil emerged more recently relative to the Middle East.

Top 20 Countries by Offshore Discovered Liquids Resources, 2000-2023



Source: Wood Mackenzie; Total resources discovered offshore including produced resources and remaining all water depths

Since 2000, Brazil and the US yielded more offshore liquids resource discoveries than any other country. The level of discovered resource underscores the overall prospectivity associated with each region.

Brazil's remaining commercial deepwater liquids reserves of ~26.6 billion barrels account for approximately 45% of the total deepwater liquids reserves remaining worldwide. Technological advances in the early 2000s enabled Brazil to unlock billions of barrels of oil reserves located in its deepwater pre-salt formation.

As a result of these discoveries and resources, both Brazil and the US GoM have developed and possess established industries to continue supporting offshore exploration and production activities across all water depths.

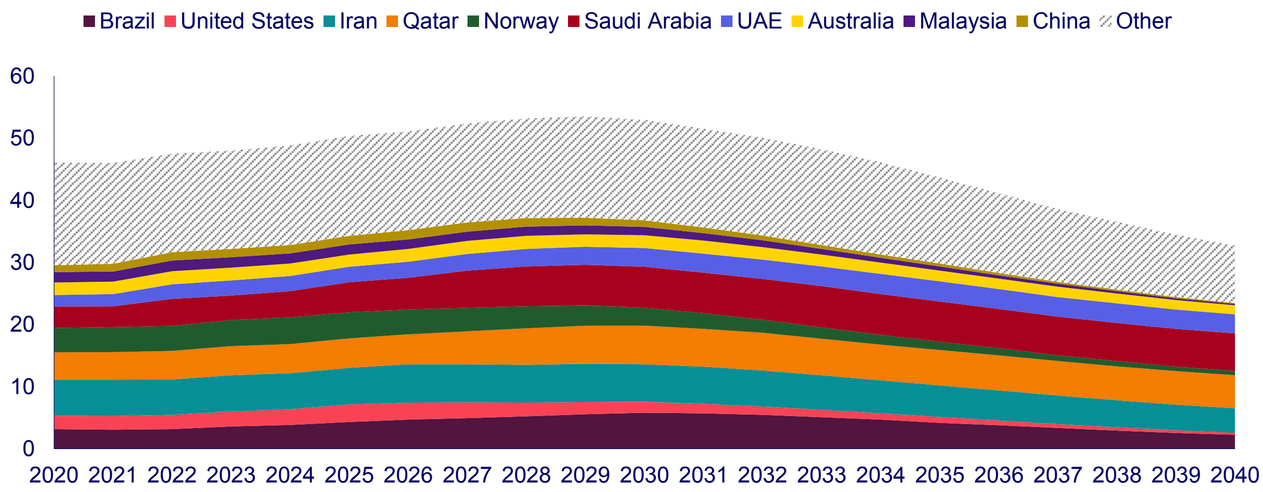
2.3. Global Offshore Production Forecasts

This section sets forth Woodmac's forecasts and expectations for global offshore production through 2040. Production estimates are based on our best estimate of likely future production from commercial assets modelled as part of Woodmac's Upstream Service and asset valuation offering. Asset valuations are conducted under Woodmac's standard economic assumption, which is based on a long-term real US$65/bbl Brent price assumption. Please note that the *economic assumption* used for commercial asset valuation purposes differs from Woodmac's *price forecast* that is derived from the fundamental supply and demand analysis. Please refer to the Appendix for complete details on the differences and methodologies behind Woodmac's price forecasts and economic assumptions.

All modelled offshore assets are aggregated at a country level below.

Top 10 Countries by Commercial Offshore Production, 2020-2040

Million Boe/d



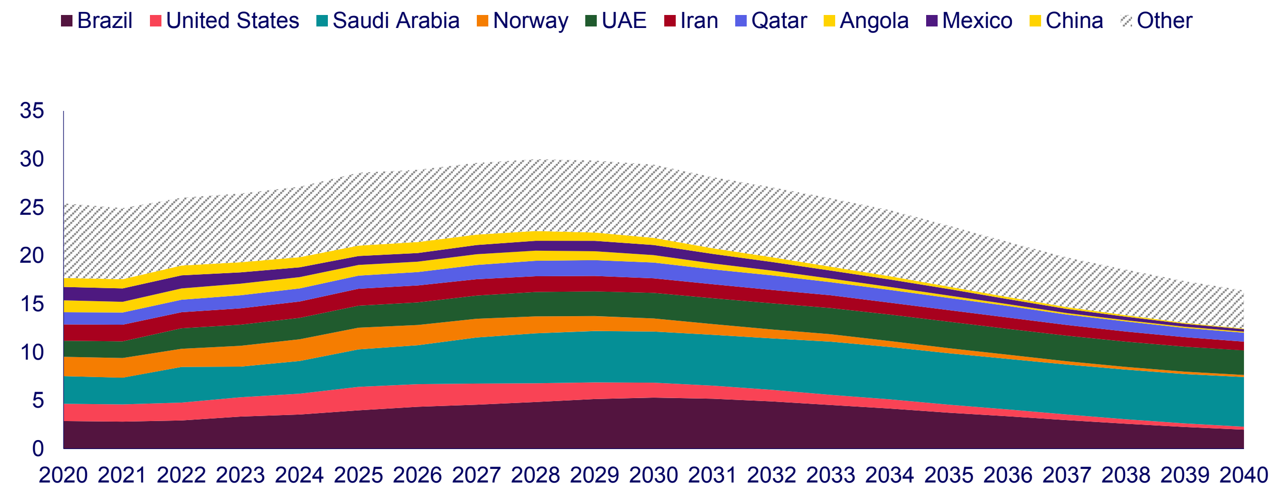
Source: Wood Mackenzie; Lens Upstream, Country Annual Production

The ten most prolific offshore producing countries in terms of 2024 expected daily production, produce 32.8 million Boe/d. This represents 66% of the total 48.8 million Boe/d produced offshore globally. Brazil and the US are the fifth and sixth largest offshore producers, respectively. Brazil is expected to account for 8% of total offshore production in 2024. The US will account for 5% of total offshore production in 2024.

On a Boe basis, Iran, Qatar, Norway, and Saudi Arabia are the largest current offshore producers, but each country produces a balanced hydrocarbon mix with a large amount of gas. Brazil and the US are more weighted toward oil. 93% of Brazil's offshore production is liquids, while the US is 85% liquids. For comparison, Saudi Arabia is 80% liquids, but the other top producers are 52% liquids or lower.

Top 10 Countries by Commercial Offshore Liquids Production, 2020-2040

Million barrels per day

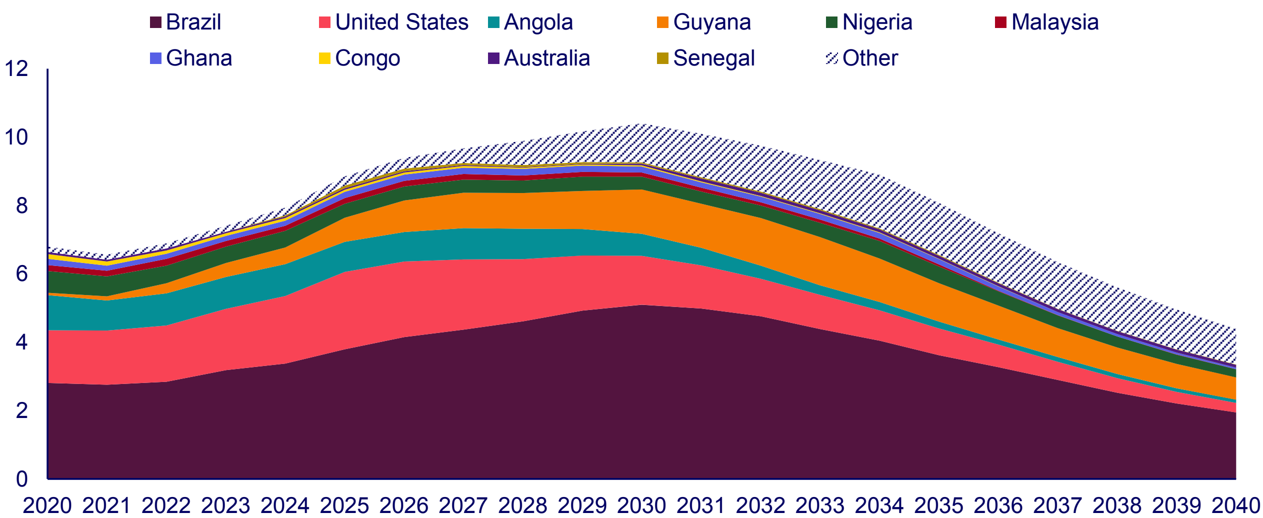


Source: Wood Mackenzie; Lens Upstream, Country Annual Production

Brazil is the world's largest producer of offshore liquids across both shallow water and deepwater at 3.6 million barrels expected per day in 2024. That represents a 13% share of the offshore liquids marketplace. The US is the fifth largest offshore liquids producer as measured by 2024 expected production, representing 8% of the market.

Top 10 Countries by Commercial Deepwater Liquids Production, 2020-2040

Million barrels per day



Source: Wood Mackenzie; Lens Upstream, Country Annual Production

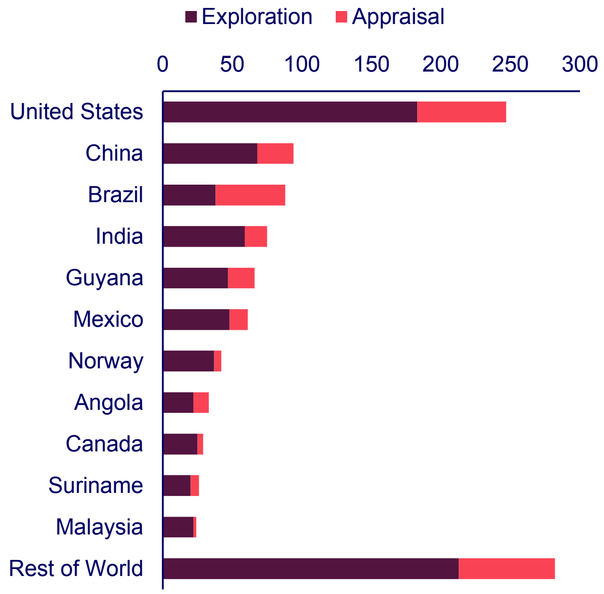
Brazil and the US GoM are the two largest deepwater markets, forecasted to produce 5.3 million barrels per day of liquids resource in 2024. This accounts for 67% of all deepwater liquids production. The two countries will also generate 52% of the total 2024 deepwater production including both liquids and gas.

Brazil remains the largest deepwater liquids producer through 2040. Current deepwater liquids production of 3.4 million barrels per day is forecast to increase by over 50% to 5.1 million barrels per day by 2030. Commercial US GoM projects exhibit declines, but new exploration across different reservoirs and identified tie-back opportunities provide potential solutions to offset declines in the 2030s. Guyana and Namibia are the only other countries currently with visible pathways to larger-scale deepwater production than the US by 2040.

2.4. Global Offshore Activity Levels

Deepwater E&A Wells Completed since 2015

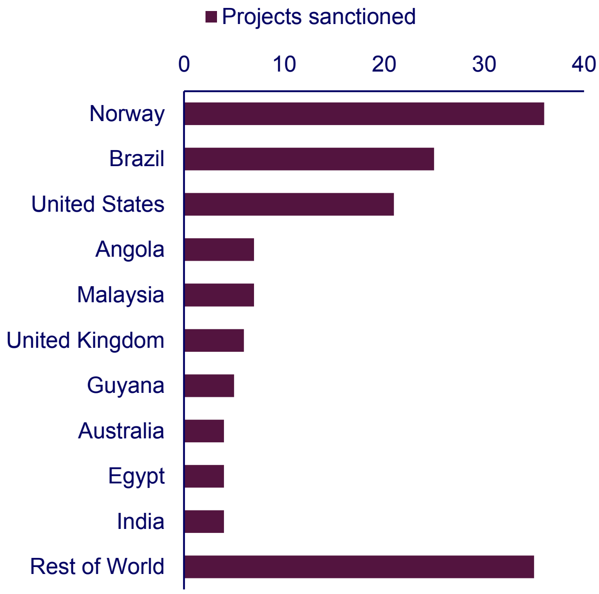
Number of wells



Source: Wood Mackenzie; All conventional offshore E&A wells completed from 2015-2023, excludes sidetracks

Offshore Projects Sanctions since 2015

Number of projects



Source: Wood Mackenzie; All sanctioned (FID) offshore projects with commercial reserves greater than 50 MMBoe

From 2015-2023, 1,067 conventional deepwater E&A wells were completed globally. The US GoM represented the most active deepwater region with 23% of total deepwater wells completed in the period.

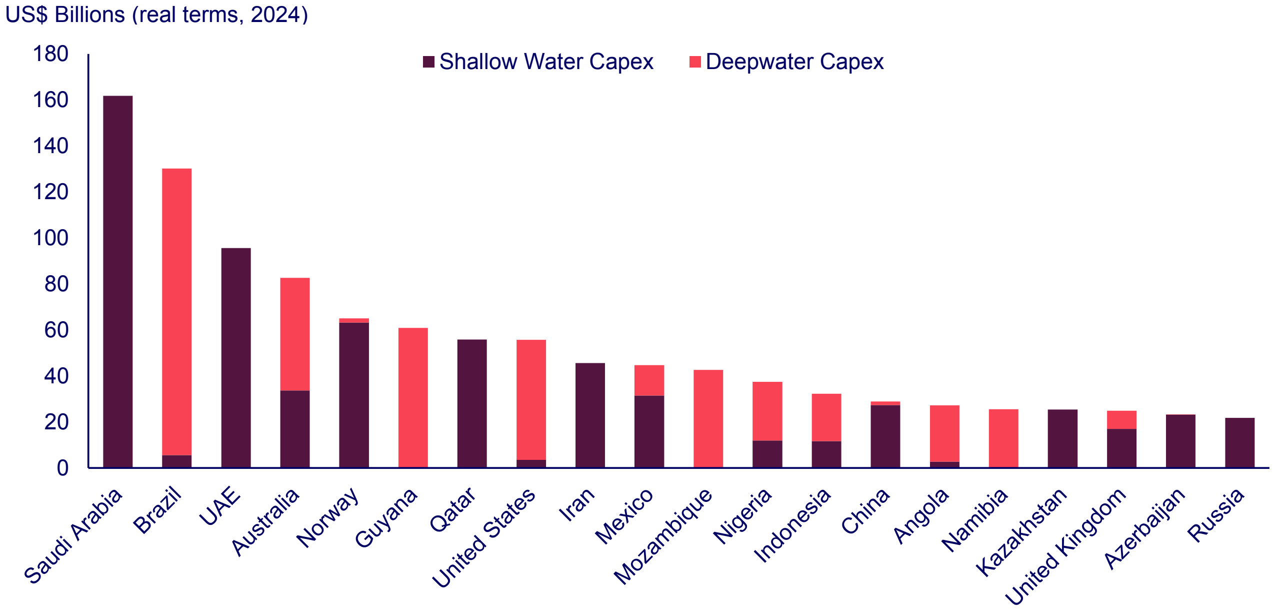
The resource potential of Brazil, evidenced by leading discovered resource volumes since 2000, also attracts ongoing E&A attention and investment. Petrobras, the publicly held state oil company of Brazil, holds exploration as a core component of its strategy. Approximately 10% of Petrobras' overall E&P budget in its 5-year plan (2024-2028) is allocated to Brazilian E&A activity. Abundant resource potential has also attracted offshore foreign investment in Brazil from several Majors and NOC's like Shell, TotalEnergies, CNOOC, Equinor, and ExxonMobil.

Activity levels establish offshore Brazil and the US GoM as among the most active and proven offshore markets globally. Note that most E&A activity in Brazil and the US GoM in recent years has focused on deepwater. Other countries like China, Norway, and India have also been very active in drilling and completing E&A wells in shallower waters.

2.5. Offshore Development Capital Expenditures

This section sets forth Woodmac's forecasts and expectations for certain countries' offshore development capital expenditures through 2040. Woodmac's forecasted capital expenditures for commercial offshore projects build up from all of the field-by-field upstream asset models, consistent with the same methodology in the preceding reserve and production forecasts. Field-level capital expenditure figures represent development capital expenditures and exclude abandonment costs. E&A costs, including both drilling as well as geological and geophysical costs, are not included in the development capital expenditure forecasts.

Cumulative Commercial Offshore Development Capex (Excluding Abandonment) by Country, 2024-2040



Source: Wood Mackenzie; Lens Upstream, Country Annual Cost

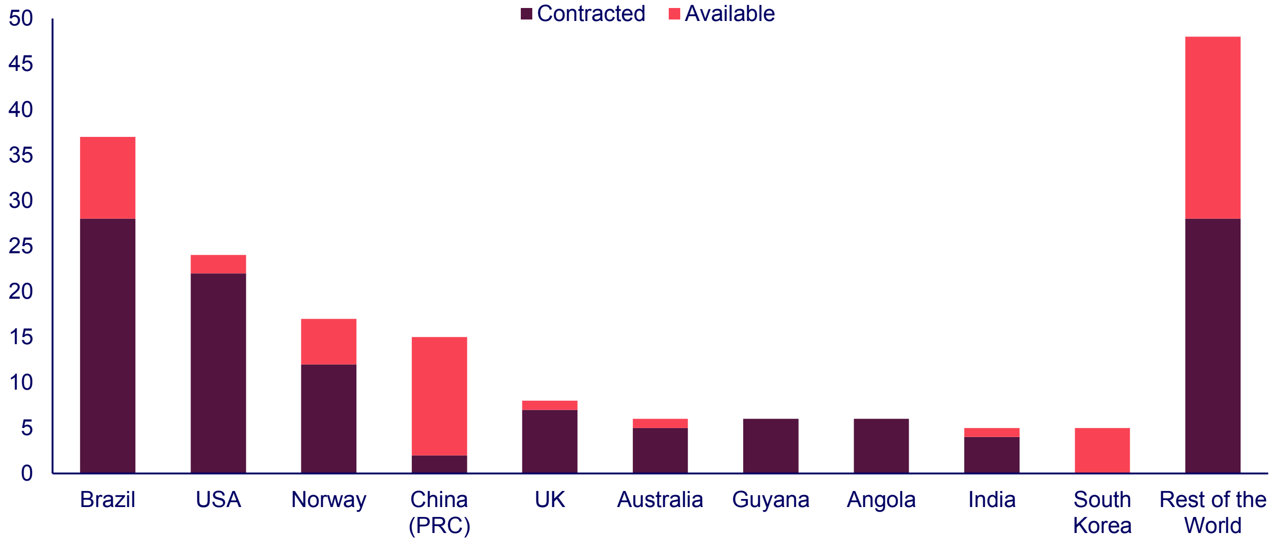
Brazil is projected to spend US$130 billion in development capital expenditures between 2024-2040, trailing only Saudi Arabia. Brazil's investment profile is more heavily weighted near-medium term relative to Saudi. US$113 billion of forecasted spending in Brazil during this time is expected to occur by 2030. Investment in commercial developments begins to fall more after 2030 while Saudi demonstrates a more stable long-term investment profile. High-impact exploration as well as expanded mature field revitalization efforts offshore Brazil represent incremental opportunities for additional development.

US offshore development capital expenditures are projected to be US$56 billion between 2024-2040 and, like Brazil, over 75% of the expected spend occurs by 2030. Brazil and the US represent the most significant investments in deepwater developments over the time horizon.

2.6. Offshore Infrastructure Summary

Contracted and Available Floating Drilling Rigs

Number of offshore rigs



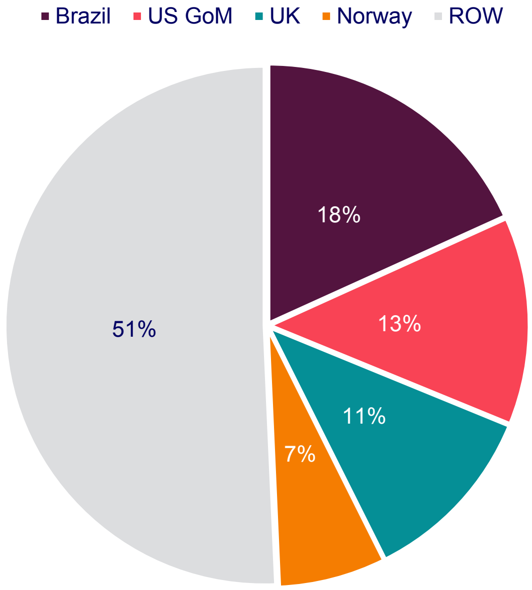
Source: Wood Mackenzie; Supply Chain Service; Semi-submersible and drill ships designed for midwater, deepwater, and ultra-deepwater

Brazil and the US GoM are the most active markets globally for high-spec floating rigs. 42% of contracted floating rigs globally operate in Brazil and the US GoM across all generations of floating rigs. All of the contracted rigs in those two markets are sixth, seventh, or eight generation rigs constructed since 2006. These newer rigs are more technologically advanced and better equipped to operate in deeper water.

Demand growth in Latin America, largely Brazil and Guyana, and West Africa puts pressure on global rig supply, especially for the newest, highest spec rigs. Brazil and the US GoM are favourably positioned due to the existing contract status for the most advanced rigs. Contracted rigs underscore the ongoing capital commitments in both regions.

Offshore Operational Production Platforms

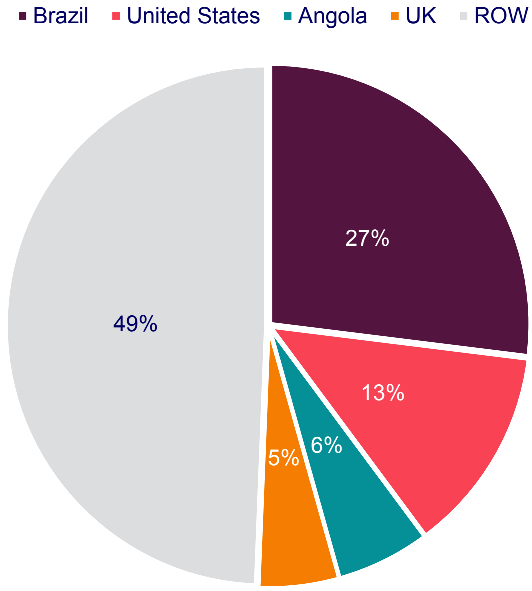
Percentage of active production platforms



Source: Wood Mackenzie; operational production platforms associated with producing fields, all water depths; fixed and floating platforms

Offshore Operational Floating Production Platforms

Percentage of active production platforms



Source: Wood Mackenzie; operational production platforms associated with producing fields, floating platforms only, all water depths

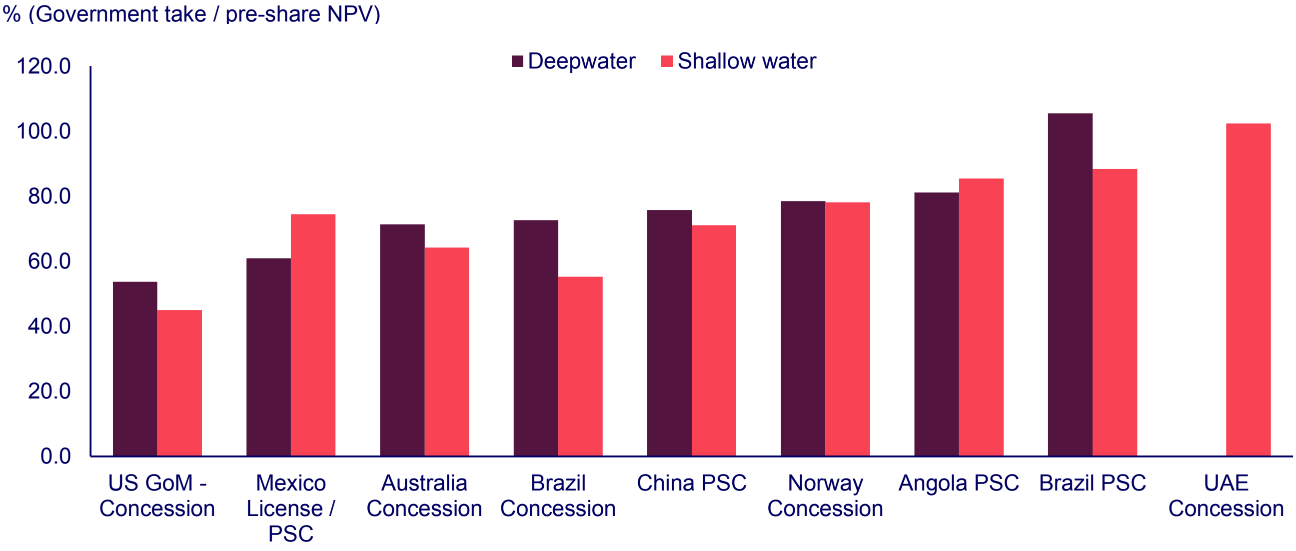
Woodmac currently identifies 779 operational production platforms offshore across all water depths. The US GoM and Brazil possess 142 and 101 total platforms respectively, or 31% of the global market. The North Sea, spanning across the United Kingdom and Norway, also possesses a number of long-standing fixed and floating platforms operating in shallower waters. Brazil and the US GoM outpace the rest of the world in terms of floating production facilities suited for mid-and-deepwater, collectively holding 40% of the overall market. Of the floating production platforms operating in deepwater fields, two-thirds are located in either Brazil or the US GoM.

2.7. Fiscal Regime Benchmarking Summary

Woodmac's Fiscal Benchmarking Tool establishes the competitiveness of current fiscal systems for upstream oil and gas projects. The Benchmarking Tool is based on a wide range of hypothetical field production and cost profiles where the only difference between model fields are the latest fiscal terms available to explorers (i.e. new licenses) in each country. This methodology allows for the comparison of different fiscal systems, as well as highlighting an investor's exposure to project upsides and downsides under different scenarios, while measuring the extent to which the government shares in those risks.

Woodmac measures total government share as a percentage of pre-share NPV for the largest offshore producing countries identified in Section 2.3. The analysis is derived from a medium-sized oil field - 50 mmbbl recoverable resource for shallow water and 200 million barrels for deepwater – with medium costs at a long-term Brent real price (2023) of US$65/bbl. The benchmark represents our "down-the-middle" scenario. The tool offers high and low sensitivities on price, resource size, and costs.

Fiscal Regime Benchmarking: Government Take as a Percentage of Pre-Share NPV



Source: Wood Mackenzie; Fiscal Benchmarking Tool; Mexico deepwater blocks are under a concession like license, while shelf blocks are regulated with a petroleum sharing agreement; NOC operated offshore production in Saudia Arabia, Iran, and Qatar are not included in Woodmac's fiscal terms database

Among material offshore oil producing regions, the US GoM possesses one of the most competitive global fiscal regimes. Producers are subject to a flat royalty rate, creating an environment where the investor retains more of the upside in a higher price environment.

Offshore production in Brazil is subject to both concessionary regimes and production sharing contracts (PSC). Brazil introduced a concessionary regime for offshore licenses when the government initially opened the upstream sector to private investment. Brazil subsequently established a PSC for the defined pre-salt polygon and other areas deemed strategic to the government. Karoon's Brazilian assets in Bauna are subject to Brazil's concessionary terms in water depths less than 400 meters. Furthermore, mature concession assets like Bauna benefit from graduated royalty terms[3] where royalties decrease as an incentive for continued investment in mature fields.

Additional details on fiscal terms and considerations will be provided in Section 3.4 for offshore Brazil and Section 4.5 for the US GoM.

[3] Source: Karoon Energy

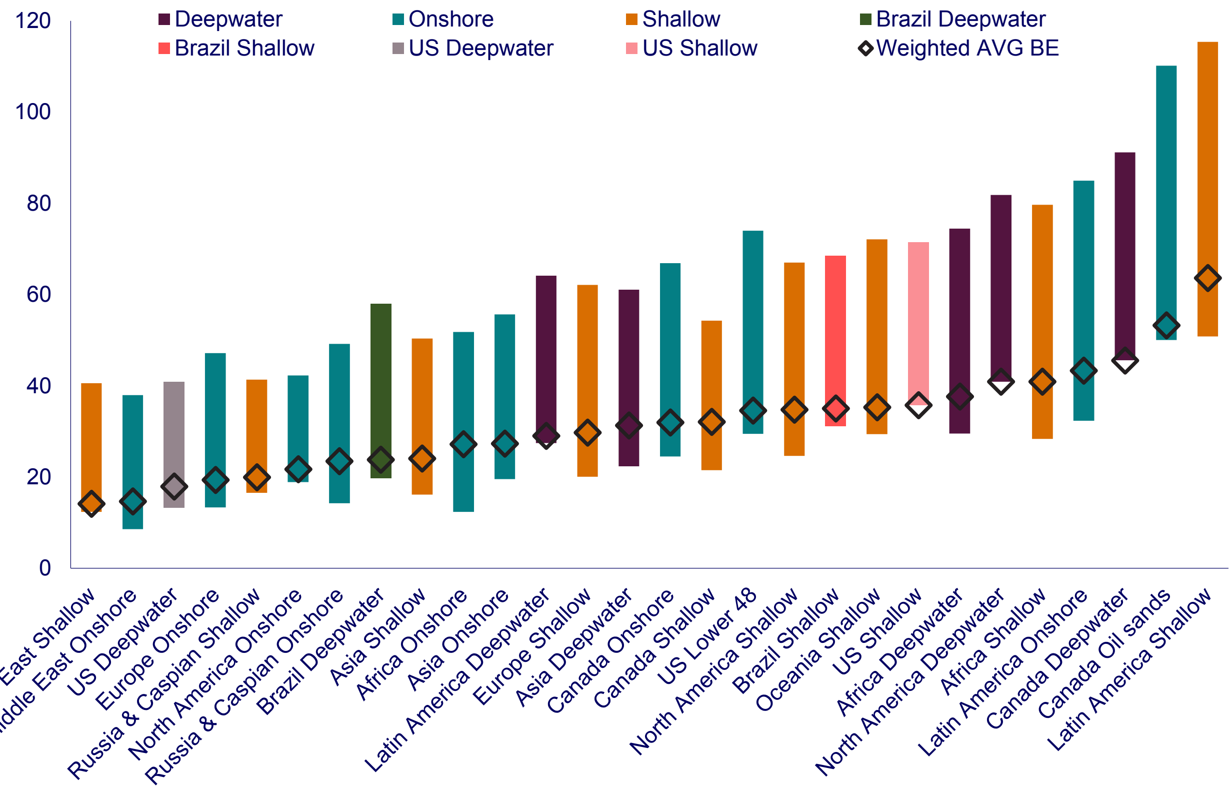
2.8. Economic Overview

Woodmac calculates point-forward breakevens (NPV 10%) for remaining commercial reserves. Economics are not run on a full-cycle basis. Asset valuations are development only and do not include any prior costs like signature bonuses, acreage costs, or E&A expenditures. Already incurred development capital is also excluded in the go forward breakeven.

The breakeven ranges illustrated below exclude the top and bottom quartile assets from each resource theme. The weighted average calculation does include all assets in each theme.

Point Forward Brent Breakeven Price by Resource Theme, 2024

Brent Breakeven NPV10, US$/Boe



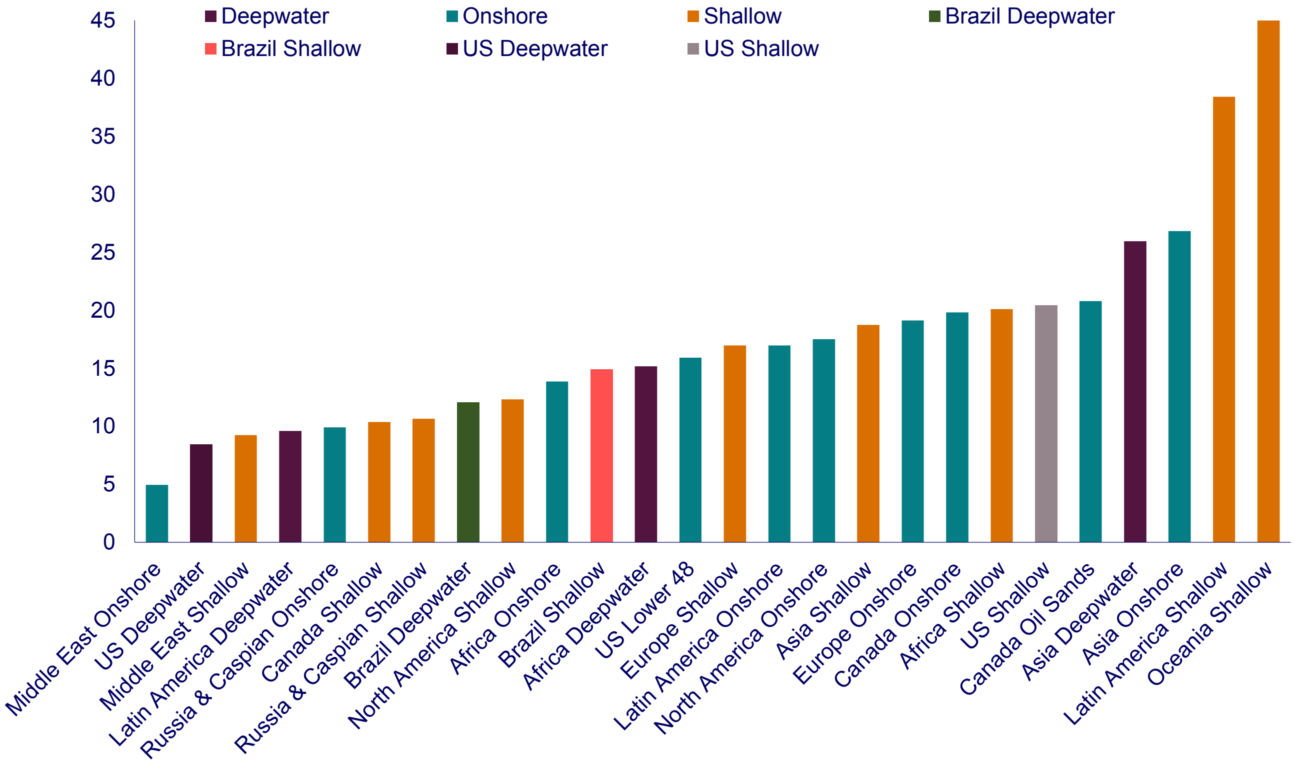
Source: Wood Mackenzie; Commercial liquids fields with remaining liquids resource >25mmbbl
Quartiles were not filtered out for Latin America Deepwater (excluding Brazil) and Asia Deepwater; commercial fields with remaining liquids reserves >25mmbbls in Latin America consist of three commercial fields in Guyana (Stabroek block), Suriname (Block 58) and the Falkland Islands, Asian Deepwater was limited to two qualifying fields in Indonesia and Malaysia

Low-cost onstream Middle Eastern reserves push that region to the bottom of the remaining resource cost curve, but the US GoM and offshore Brazil compete globally in terms of point forward weighted average breakeven for remaining commercial reserves. The US GoM possesses a weighted average remaining resource breakeven of US$17.97/Boe, while Brazil's offshore average stands at US$23.84/Boe. Offshore Brazil and US GoM represent the most attractive deepwater regions in terms of remaining resource breakevens.

The US GoM possesses one of the narrowest variances between the minimum and maximum range, demonstrating more defined economics and greater relative levels of certainty regarding economic forecasts.

Unit Production Cost[4] by Resource Theme, 3-yr Aggregate Forecast Per Barrel Expenditure 2024-2026

US$/Boe



Source: Wood Mackenzie; Onstream, commercial liquids fields with remaining liquids resource > 25mmbbl

The forward three-year per unit production costs provide a proxy for the short-run marginal costs for onstream production across different resource themes and regions. Low operating expenditures reflect greater near-term resilience to commodity price declines for onstream assets.

Middle Eastern reserves continue to have the lowest operating costs in the world, but the US GoM and offshore Brazil both possess competitive unit production cost profiles. Production scale in each region supports lower per unit costs, particularly relative to other non-OPEC producing regions that do not match the US GoM and Brazil in scale and established operating history. Karoon's 2023 unit production cost of US$11/Boe[5] is below average for Brazil shallow water (water depths less than 400 meters). The US GoM acquisition closed in December 2023, so 2024 is the first full year with exposure to competitive US GoM deepwater margins.

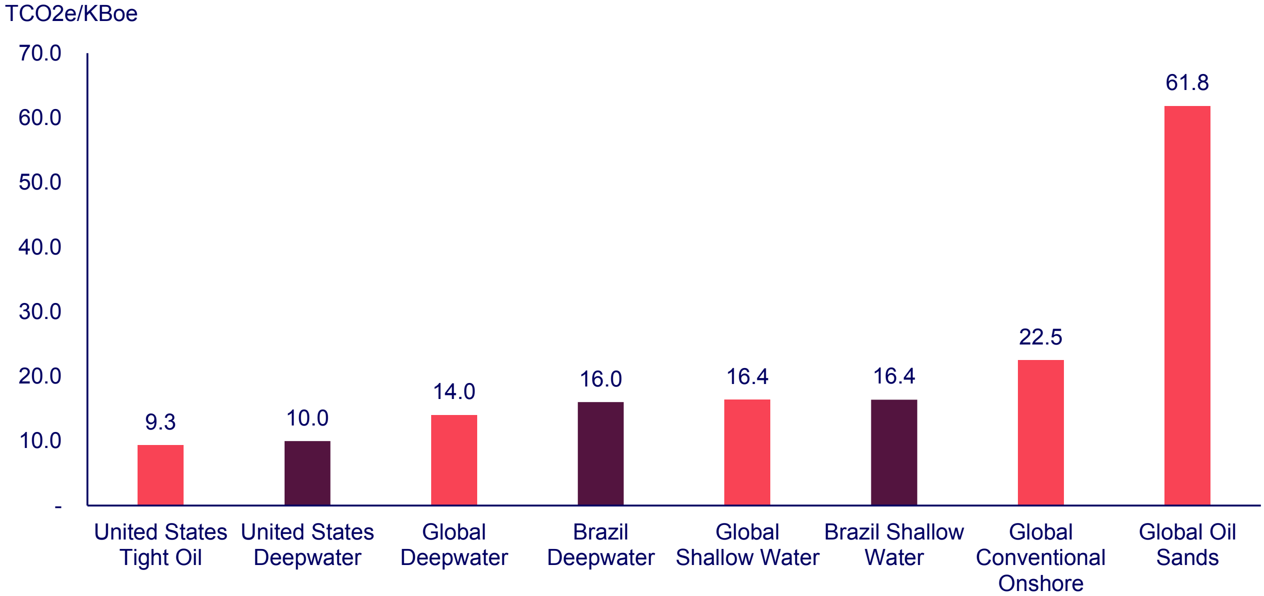
[4] Note: For the purposes of this report, unit production costs as defined only include fixed and variable operating expenses, transportation tariffs, and leasing costs. Royalties and G&A expenses are excluded from the unit cost

[5] Source: Karoon Energy

2.9. Upstream Emissions Intensity

This section sets forth Woodmac's forecasts and expectations for upstream emissions intensity by resource theme through 2035. Woodmac monitors and forecasts emissions intensity by resource theme and region through its Emissions Benchmarking Tool. For upstream assets, the emissions boundary encompasses operations required to produce oil or gas between the wellhead to the point at which it is available for sale (e.g., on the water for tankered oil, or at a refinery gate, or head of a major gas transmission line). Emissions from the following upstream activities are considered: drilling, production, and processing along with associated CO_2 venting, flaring and methane losses.

Scope 1 & 2 Emissions Intensity by Resource Theme and Selected Regions, Average from 2024-2035



Source: Wood Mackenzie; Emissions Benchmarking Tool; Scope 1 & 2 emissions only

The US GoM possesses low Scope 1 & 2 emissions intensity compared to other producing regions. One of the principal advantages facilitating low emissions intensity, even compared to other deepwater production, is a mature and extensive pipeline network. The existing pipeline network mitigates the need to flare gas.

Brazil also competes favorably in terms of emissions intensity. Brazil benefits from large-scale developments with higher well productivity. Higher single well recoveries also enable more production from fewer wells relative to other resource themes. Brazil and other deepwater regions also manage emissions with highly engineered and specialized production solutions, including re-injecting associated gas into reservoirs to enhance oil recovery and eliminate the need to flare gas.

2.10. Corporate Divestments and Portfolio Rationalizations

Broad sector pressures on returns on capital and emissions reductions are expected to continue to influence portfolio strategy going forward. Larger diversified producers with global portfolios continue to actively rationalize upstream portfolios and shift the focus towards more advantaged and resilient barrels that possess low breakevens and low emissions. There is also a materiality aspect where smaller assets in a larger operator's portfolio could be non-core and would be better exploited by other smaller operators.

This dynamic creates additional opportunities for independent operators like Karoon. The most active asset sellers are the Majors. In general, the Majors possess strong balance sheets, so targeted divestment activity is more geared towards portfolio optimization rather than collecting proceeds to support capital structures and shareholder returns.

The Majors are still leaning into upstream, especially in the near-to-medium term. European Majors (Euromajors) like BP, Equinor, and Shell initially set aggressive targets to reduce upstream production and shift more quickly towards renewable energy sources. However, a refocus on global energy security as well as competitive upstream returns have led to revisions and a slower pace of transition away from hydrocarbons. Still, the Major peer group collectively holds divestiture targets that will provide subsequent opportunities for inorganic growth for independent and more focused upstream operators.

Woodmac's Major peer group includes the following producers:

- **BP:** initially set very aggressive upstream reduction targets, but has revised plans to a more modest decline. The initial target was to shrink production by 40% by 2030, but that has been revised down to 25%. Still, BP will need to sell ~200,000 Boe/d in the coming years to achieve its revised 2030 production goal of 2 million Boe/d

- **Chevron:** Following its announced acquisition of Hess Corporation, Chevron aims to generate US$10-15 billion in pre-tax divesiture proceeds by 2028

- **Eni**: plans for net acquisition inflows of US$1.0 billion by 2026 prior to its US$2.6 billion (net to Eni) acquisition of Neptune Energy in 2023. Adhering to the prior target would imply US$1.6 billion of planned divestitures over the next two years

- **Equinor**: the company does not have a stated divesiture target; however, portfolio rationalization remains a component of Equinor's overall upstream strategy

- **ExxonMobil**: ExxonMobil does not have a stated divestment target

- **Shell**: New management reiterated that upstream remains a focus of Shell's business for the foreseeable future. New leadership committed to sustaining investment and volumes at least through 2030, while previous leadership only talked about sustaining cash flow. Deepwater Brazil and the US GoM remain core focus areas. Shell did indicate that while it is committed to upstream, it will look to simplify and high-grade its upstream portfolio

- **TotalEnergies**: No stated targets, but recycling capital through non-core asset sales and country exits could help fund planned investments in Namibia. TotalEnergies is focused on high-grading the portfolio around low-cost and low-emission fields. It exited its Canadian Oil Sands position in 2023 as evidence of this strategy

Overall, the Euromajors have been net sellers while the US Majors have reinforced commitments to sustainable production through large corporate acquisitions, notably 2023 announcements of Pioneer Natural Resources for ExxonMobil and Hess for Chevron. Corporate consolidation can boost this further as buyers indicate plans to high-grade acquired portfolios once corporate acquisitions have closed.

Large Independents and National Oil Companies (NOC) replicate these strategies to varying degrees as well. Petrobras' divestment of mature fields in Brazil provided Karoon its entry opportunity into the country. Large producers, led by the majors, will continue to trade assets and rationalize upstream portfolios. The net effect will be additional opportunities for more focused and nimble Independents.

3. Brazil Offshore Market Background and Dynamics

Brazil is the largest offshore producer of liquids globally. Brazil's offshore scale and operating history demonstrate a proven track record supported by an established supply chain and service sector. Furthermore, the industry is a critical driver for the country as a whole and the commercial opportunities associated with the volume of recoverable resources have attracted the world's largest oil and gas exploration and production companies.

3.1. Brazilian Upstream Summary

Brazilian Upstream Key Facts

Remaining Commercial Offshore Liquids Resources	27.5 Billion barrels of oil equivalent
Liquids production (2024 expected)	3.5 Million barrels per day
Liquid reserves / production	21 years
Remaining Commercial Offshore Gas Resources	2.9 Billion barrels of oil equivalent
Gas production (2024 expected)	0.3 Million barrels equivalent per day
Gas reserves / production	25 years

Brazil's offshore sector drives its overall upstream oil and gas industry. In 2024, 97% of Brazil's total liquids production and 81% of gas production is projected to come from offshore basins. Brazil's offshore basins cover more than 4.4 million square kilometers, 82% of which lie in water depths greater than 400 metres.

Brazil first started producing oil offshore in 1940 in shallow water coastal basins. Petrobras, the state-owned national oil company of Brazil, held a monopoly until 1997 when the government opened Brazil's upstream sector to private investment. Petrobras is still the dominant producer in the country, but large and established oil and gas companies from all regions have actively invested in Brazil's offshore industry (largely Majors and other NOCs).

The sector began to grow in the late-1970s with activity shifting towards the Campos basin. Production from the Campos basin transformed Brazil's production base, establishing Brazil's standing in deepwater production globally and elevating the stature of the sector within the country.

The Santos basin south of the Campos basin emerged in the mid-2000s as one of the most active and prospective exploration plays in the world due to pre-salt potential. Technological advances unlocked geologic formations located underneath thick layers of salt deposits. Petrobras first discovered the giant pre-salt Tupi field (renamed Lula) in the Santos basin in 2006.

The scale of pre-salt resources facilitated a transfer of rights between Petrobras and the Brazilian government. Petrobras discovered the resources and held the exclusive rights; however, financial standing and overall capital requirements meant it would not be possible for a single operator to properly develop the resource base. The transfer effectively allowed the government to compensate Petrobras for prior investments in exchange for the ability to auction off excess resources to other companies through a competitive bidding process. The ability to participate in the development of pre-salt resources attracted additional interest and investment from large oil and gas companies from across the globe.

Karoon's mature Santos basin assets are located in post-salt reservoirs. As some operators have shifted focus towards the pre-salt it has created advantageous opportunities for niche strategies to acquire, redevelop, and revitalize more mature post-salt fields.

The offshore Campos and Santos basins account for 94% of Brazil's remaining offshore reserves, both commercial and technical. The basins' combined production scale provides significant royalty and tax revenue for the government. The sector is forecasted to contribute US$39 billion in royalties and direct federal taxes to the government in 2024.

The impact of Brazil's offshore sector on global oil markets is evident in Brazil's late 2023 decision to begin participating in OPEC+ discussions. While Brazil will not be a full OPEC+ member or take part in output cuts, its inclusion underscores the role and influence Brazil's offshore sector possesses.

3.2. Brazilian Resource and Production Forecasts

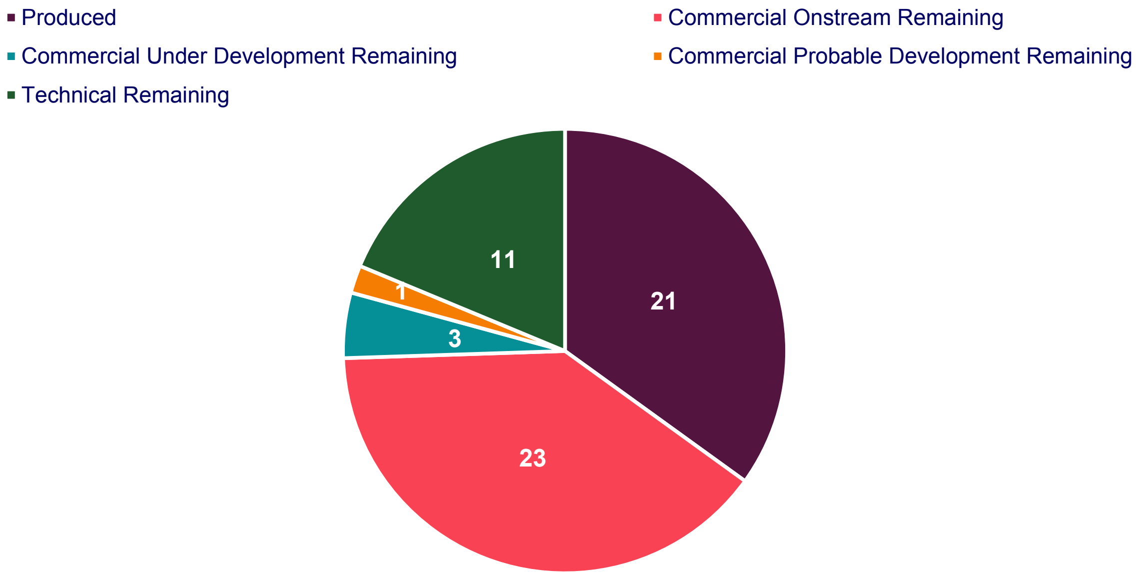
The scale of discovered resource volumes in the Campos and Santos basin provides Brazil with more commercial liquids resources remaining than any country outside of the Persian Gulf region. Unlocking the pre-salt reservoirs in the Santos basin solidified Brazil's place at the forefront of deepwater development. The Santos basin accounts for 77% of all remaining commercial liquids reserves offshore Brazil.

Further resource growth is possible with ongoing redevelopment efforts by Petrobras and smaller Independents in the more mature Campos basin. Exploration in Campos pre-salt features as well as frontier exploration in other areas offshore Brazil provide even more prospective resource upside.

Brazil has already produced over 20 billion barrels of liquids offshore. Prolific remaining resource potential attracts continued investment, but more mature developments in the Campos basin and onstream projects in the Santos pre-salt reservoirs demonstrate proven development execution and visible production longevity.

Brazil Remaining Commercial Offshore Liquids Resources

Billion Boe



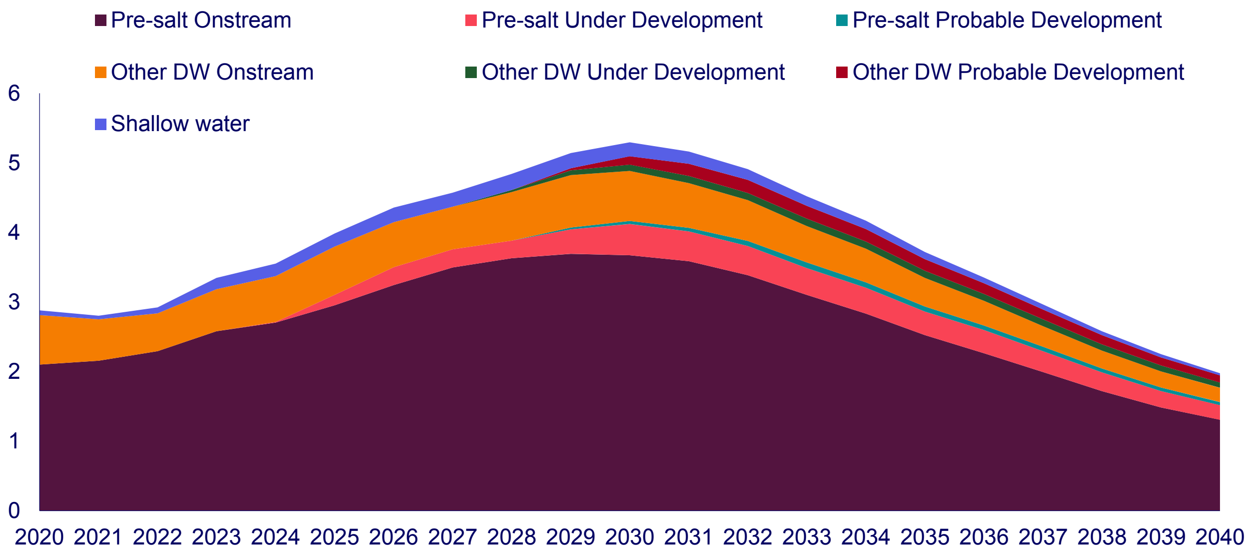
Source: Wood Mackenzie; Lens Upstream, Country Reserves

The scale of produced volume points to a strong history, but commercial onstream remaining volumes of 23 billion barrels demonstrates that Brazil's upstream sector is poised for continued growth. In addition to onstream resources, there are sanctioned and probable developments that could add another 4 billion barrels of visible resource potential.

The rest of this section sets forth Woodmac's forecasts and expectations for Brazilian offshore liquids production and offshore capital expenditure through 2040.

Brazil Commercial Offshore Liquids Production, 2020-2040

Millions of barrels per day



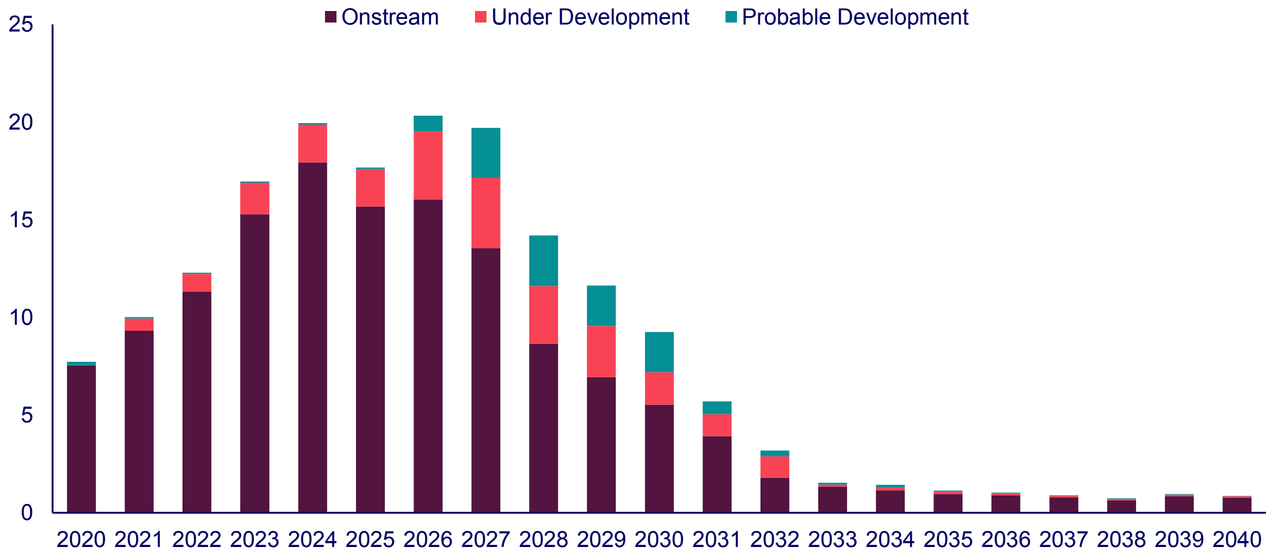
Source: Wood Mackenzie; Lens Upstream, Field Annual Production

Brazil's offshore liquids production surpassed 3 million barrels per day in 2023, but rapid growth is expected to continue. Offshore production is forecast to increase another 60% through the end of the decade and exceed 5 million barrels per day in 2030.

Brazil is currently responsible for 42% of deepwater liquids production globally. Forecasted production growth pushes the percentage up to 49% by 2030. Growth in the pre-salt drives the near-to-medium term forecast. 75% of current liquids production comes from the Santos basin, while the Campos basin accounts for 23%.

Brazil Commercial Offshore Capex (Excluding Abandonment) by Development Status

US$ Billion (real terms, 2024)



Source: Wood Mackenzie; Lens Upstream, Country Annual Cost

Total development capital expenditures, excluding abandonment costs, is expected to average over US$18 billion per year (real terms, 2023) over the next 5 years. That level of ongoing investment supports the forecasted production growth profile. Additional investment continues in E&A activities as well, but that spend is not reflected in the development capital forecast.

The capital program reflects the planned expenditures for commercial projects, which is why the development spend starts to fall beyond the next 5 years. Woodmac models expenditures for sanctioned and anticipated projects, but as commercial projects are completed and capital requirements roll off, additional projects will be evaluated and potentially sanctioned to offset production declines.

3.3. Infrastructure Summary and Associated Supply Chain

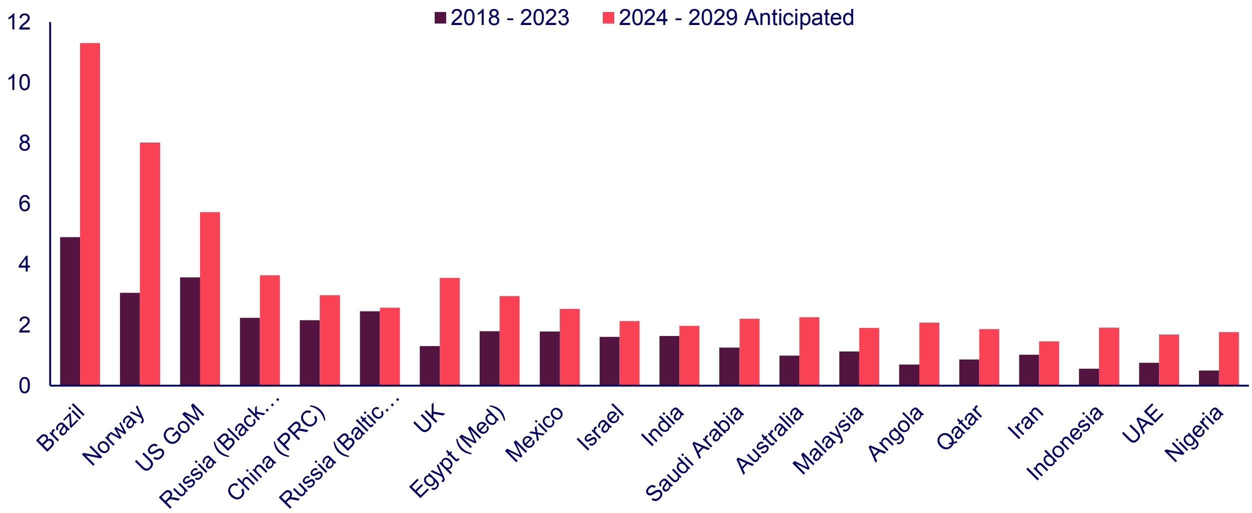
Brazil possesses an active supply chain characterized by global leadership in rig contracting, SURF (Subsea, Umbilicals, Risers and Flowlines) installations, and FPSO (Floating Production Storage and Offloading) awards. The supply chain corresponds with a service sector and local labor force in place to support ongoing exploration and production activities.

Brazil is the world's largest market for floating drilling rigs (drillships and semi-submersibles). Brazil currently has 28 floating rigs contracted, representing 23% of all contracted floating rigs globally. The market also possesses 9 additional rigs in place that are available for contract. Only China has more available floating rigs.

Brazil's leadership in the floating rig market is more pronounced when considering the new, higher-specification floating rigs. All 28 contracted rigs are Generation VI–VIII, increasing the overall share in the high-specification market to 26%. These rigs are more in demand and carry higher day rates. The US GoM and Norway have 22 and 12 of these rigs contracted respectively, and no other country possesses more than 6.

Global Subsea, Umbilicals, Risers, & Floaters Installations: Top 20 Countries

Total SURF lines installed, thousand kilometers



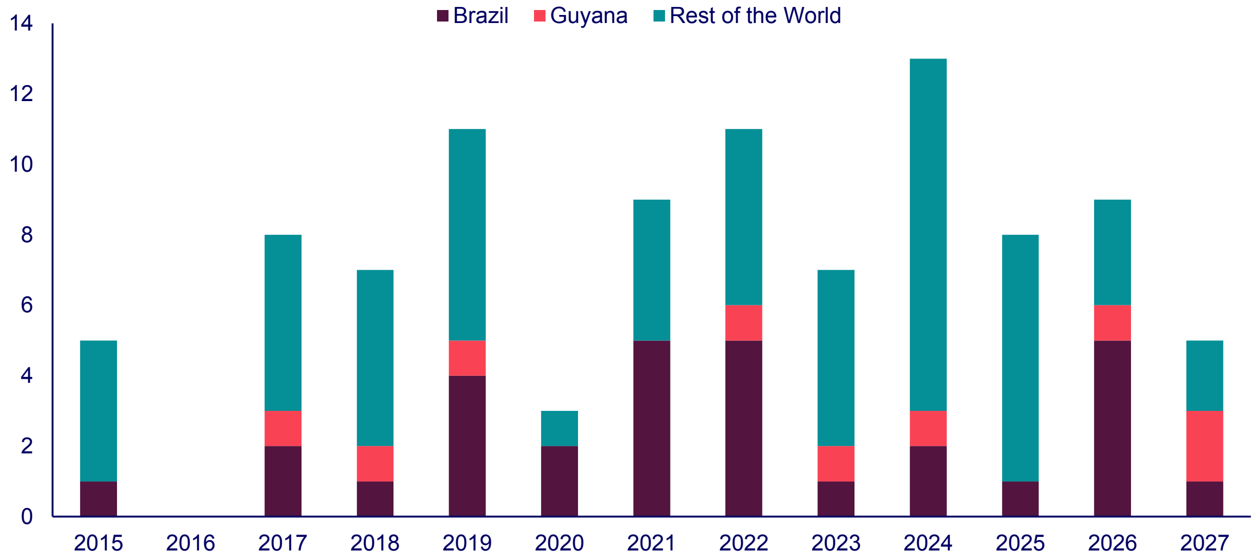
Source: Wood Mackenzie; Supply Chain / Subsea, Umbilical, Riser, & Floater service

Brazil is also a clear market leader in terms of SURF installations for both actual installations and forecasted demand. Petrobras alone charters 15 pipeline lay vessels on long-term charters to support ongoing development activities. Petrobras' activity and the total amount of SURF lines installed indicate that the global fleet of installation vessels is weighted towards Brazil. Woodmac tracks a primary fleet of 61 vessels available for subsea installations.

Contracted rigs and SURF installations illustrate high exploration and activity levels, but transportation infrastructure is relatively limited in scope given the scale of offshore production. Offshore oil production in the country, particularly deepwater, is tanker-loaded, shipped to coastal terminals and refineries or exported. The amount of production coupled with less pipeline infrastructure positions Brazil as the most active market in the world for FPSO installations. Brazil's share in the global FPSO market directly links to its standing in terms of overall production platforms highlighted in Section 2.6.

FPSO by Country by Hull Award Year

Number of FPSOs awarded



Source: Wood Mackenzie; Supply Chain / Offshore Production Systems Service

Woodmac's Offshore Production Systems service tracks production facilities, including new facility awards and forecasted awards based on expectations from visible probable developments and market intelligence. Brazil accounts for 30 FPSO awards from 2015 through the 2027 forecast. Guyana possesses 9 FPSOs in the forecasted period, while 24 other countries collectively account for the remaining 57 facilities.

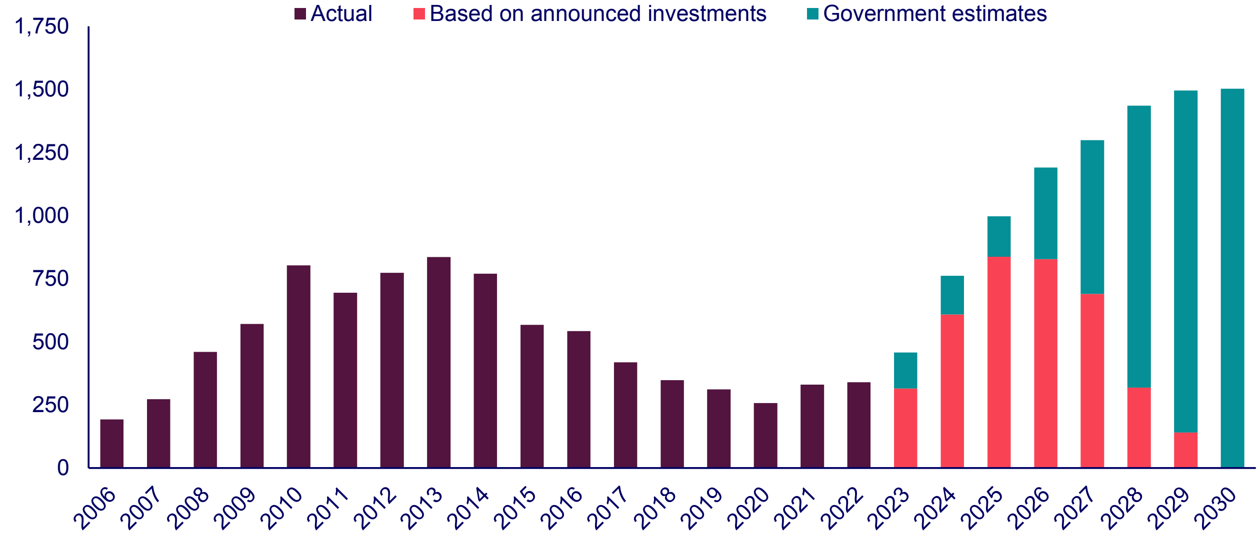
Brazil not only leads the market in terms of total facilities, but it also demonstrates facility scale. The average maximum daily oil capacity across those 30 production facilities is 137 thousand barrels of oil per day (including forecasted but not finalized awards). The average oil capacity for facilities already awarded is 157 thousand barrels of oil per day. Guyana is the only country with more than two awards that holds a higher average size.

Campos basin shallow water possesses an existing pipeline system that can transport oil from mature fields to the shore. Other local pipeline systems connect onshore fields that are not close to demand centers to export terminals. There is also an ongoing effort to develop additional gas pipeline infrastructure to bring associated gas from deepwater pre-salt fields to the shore.

There are currently 17 operational refineries in Brazil with an additional one under construction. The operational refineries possess crude distillation unit capacity of 2.0 million barrels per day and represent a sizable local demand center for offshore liquids production.

Brazilian Upstream-Related Jobs[6]

Thousands of people



Source: ABESPetro Summary Report 2022 (Brazilian Association of Oilfield Services and Companies)

All of the supporting infrastructure underscore the scale of the supply chain and labor market. The sector has a proven track record of growth and development. Job growth in the sector has recovered following a decline that started with an initial price crash in late 2014/2015 that bottomed out amid the COVID-19 pandemic in 2022. The trajectory recovers to 2014 crash highs in the coming years based on announced investments in the sector. Further government estimates project that the job count could reach an all-time high of 1.5 million employees by 2030.

To encourage the growth of the local service sector, the Agência Nacional do Petróleo (ANP) stipulates a local content requirement in each licensing round. Local content policies have been amended in recent years to reduce obligations and it is no longer a biddable item, but it remains an ongoing obligation that helps promote the local industry.

3.4. Brazilian Upstream Fiscal Regime Summary

Brazil's offshore oil and gas sector is governed by two separate fiscal regimes. Most offshore assets are subject to a concession regime; however, a PSC is applied to pre-salt developments located in the defined pre-salt polygon area. The PSC regime is also applicable to other areas deemed strategic by the government. Karoon's Santos basin assets are subject to concession terms.

Concession terms were first introduced in 1997 when Brazil's upstream sector was opened to private investment. The newer PSC regime went into effect in October 2013 following the discovery of huge offshore resources in the pre-salt. The scale of resources discovered led the government to reassess how to govern its upstream sector and extract more value from discovered resources. Licenses are awarded under both regimes in regular licensing rounds that are organized by ANP.

Offshore Brazil concession terms consists of a fixed 10% royalty, corporate income tax, and an additional Special Participation Tax (SPT), or profits tax, that varies with time, location, and production. Signature bonuses are biddable in concession licenses, but relatively friendlier investor terms compared to the PSC create a very competitive bidding process. There is no automatic state participation in concessions, although Petrobras regularly participates in licensing rounds. These terms represent the most current terms that would be available for a new license.

Supplemental to the current terms, ANP permits lower graduated royalty provisions in order to incentivize continued investment and intervention in more mature fields. ANP determined eligibility of any field is discretionary and is assessed based on the economic benefit for government entities related to an operators development plan and the associated

[6] Source: Brazilian Association of Oilfield Services and Companies (ABESPetro)

production uplift that would not otherwise be produced without the incentive. Karoon's approved Bauna development plan benefits from a reduced royalty. The royalty to be applied is 7.5% for incremental production up to 50% higher than the base production profile (the production base before the start of the intervention program and reinvestment), and 5.0% for production greater than 50% higher than the base[7]. This graduated royalty regime demonstrates supportive policies and incentives that encourage continued investments in mature fields.

PSC terms carry a fixed 15% royalty, an 80% ceiling for cost recovery, and a biddable government profit share in addition to the corporate income tax. Costs incurred by the investor for exploration, development, and production can be recovered against the gross revenue generated by the sale of oil and gas. Cost recovery allows the private investors to recover their costs before applicable profit sharing with the host government. The base government profit share rate is biddable, and historically has varied with block prospectivity.

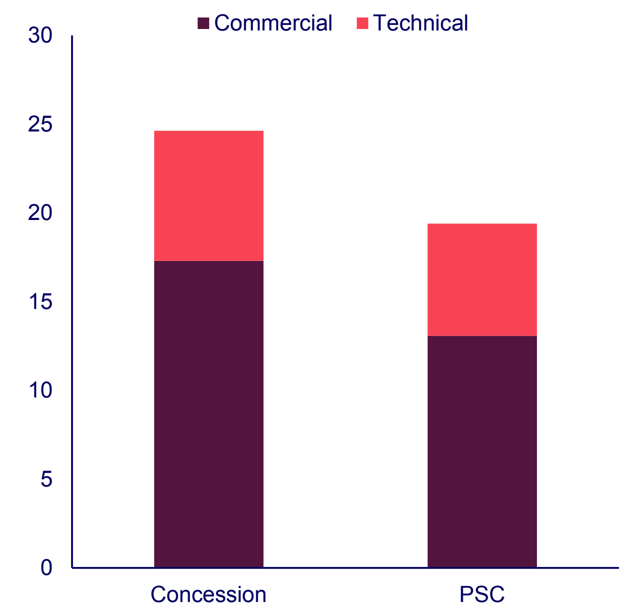
Petrobras holds the option, but not the requirement, to purchase a minimum 30% equity share in any winning bids in the PSC pre-salt developments, but the NOC is not carried during either exploration or development. It also regularly participates as the primary bidder in PSC license rounds as well. Petrobras' option is separate from the biddable government profit share.

Both regimes are subject to a range of indirect taxes at federal, state, and local levels. These taxes can add approximately 15-20% to overall project costs, but the total tax burden from indirect taxes varies from project to project. Major factors that influence the level of taxation include the amount of equipment that is imported versus sourced domestically and the proportion of tangible and intangible costs.

The Brazilian concession is a regressive fiscal system where the government receives a higher share of project value from less profitable projects. The PSC regime is regressive as well, but the relative slope is flatter. Concession projects are more favorable to investors than PSC projects due to the lower overall rates of profit sharing and state's equity.

Remaining Offshore Resources by Fiscal Regime

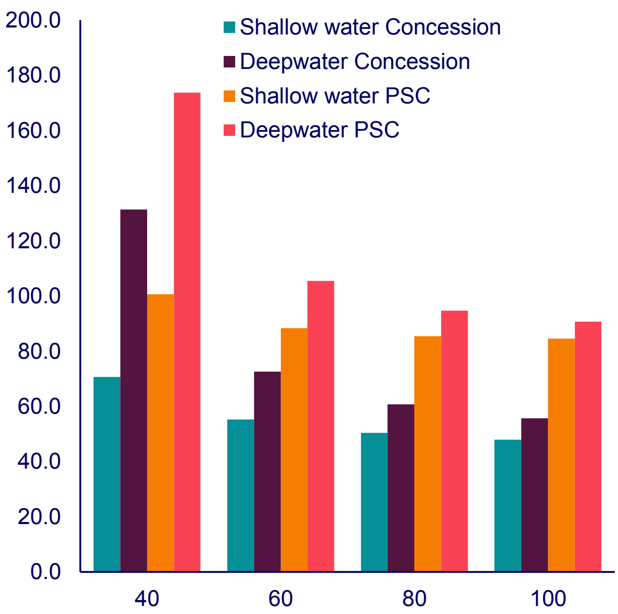
Billion Boe



Source: Wood Mackenzie; All water depths

Government Share by Oil Price Sensitivity

% (Government take / pre-share NPV)



Source: Wood Mackenzie; Fiscal Benchmarking Tool
All water depths (200mmbbl), Medium Costs

Brazil's fiscal terms have been mostly stable across both regimes since the introduction of the PSC. Since the PSC was approved in 2011 (and implemented in 2013), there have only been two notable changes. In 2015, Rio de Janeiro State's

[7] Source: Karoon Energy, Australian Securities Exchange (ASX) Press Release (07 October 2022)

legislature approved new local taxes for value-added tax on wellhead production and an environmental monitoring fee. Both laws are being challenged in Brazil's Supreme Court and are still pending a final decision. The other changes in 2017 were improved cost recovery and profit-sharing tiers for new PSC exploration licenses that benefit the producer.

Brazilian fiscal contracts do not include stability provisions; however, terms have remained consistent. In general, more stability provides operators with greater levels of certainty when making an investment decision.

3.5. Government Revenues

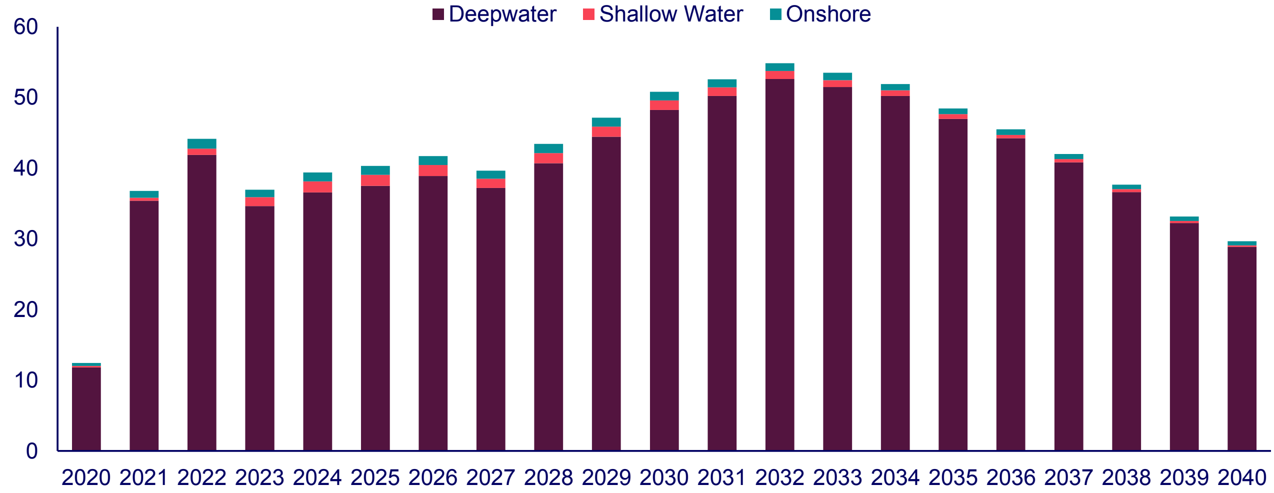
This section sets forth Woodmac's forecasts and expectations for Brazil's revenue from oil and gas activity through 2040.

The oil and gas sector provides an important contribution to Brazil's overall economy in terms of government revenue, employment, and investment. In 2023, the Brazilian government collected US$461 billion in tax revenues[8]. Upstream oil and gas activities contributed US$37 billion, or 8% of that tax revenue. Upstream tax revenue includes revenue generated from royalty payments and other direct federal taxes.

Overall, the oil and gas sector makes up approximately 10% of Brazil's US$1.9 trillion[9] overall GDP when including associated services and infrastructure that support the production of oil and gas. There are also additional indirect contributions to the economy based on employment, job creation, and foreign investment. Ownership in Petrobras also provides the government with supplementary dividend income that is not factored into the tax revenue.

Forecast Brazil Government Revenues from Oil and Gas Activity

US$ Billion (nominal terms)



Source: Wood Mackenzie; Lens Upstream, Country Annual Royalty and Government Take

Upstream oil and gas operations from commercial fields currently modelled are forecasted to generate an additional US$372 billion in tax revenue for the government from 2024-2040 using Woodmac's economic assumption of US$65/bbl Brent real prices (2023) long-term and production forecasts set forth in Section 3.2. This equates to an average of US$31 billion per year.

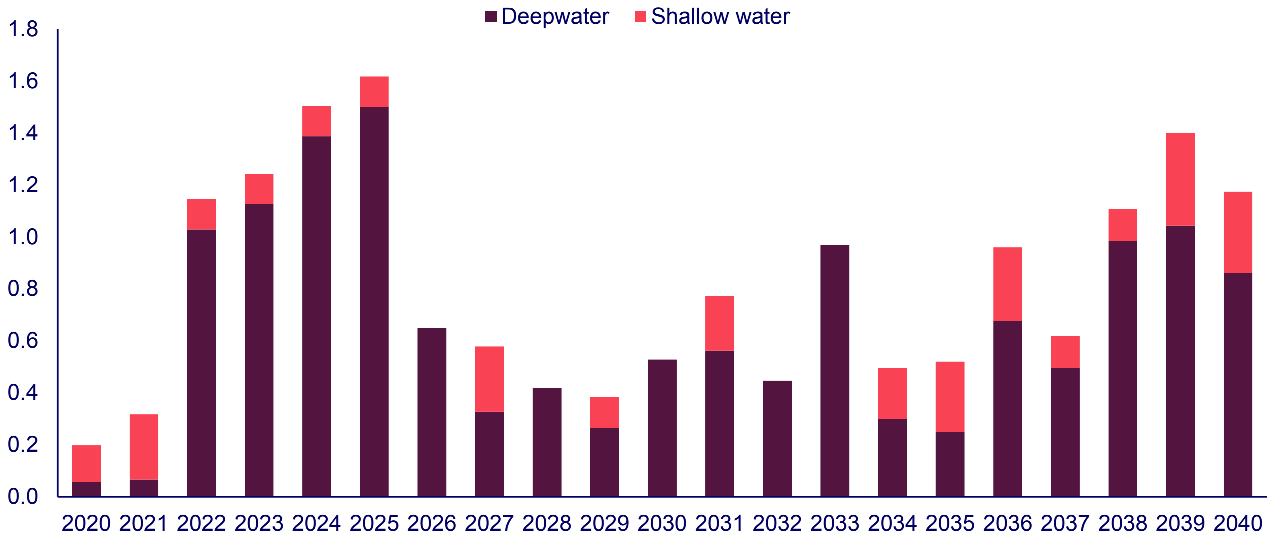
[8] Source: Brazil Federal Revenue Service

[9] Source: World Bank; United States International Trade Association

3.6. Brazilian Abandonment Requirements

Brazil Commercial Offshore Abandonment Capital Expenditures, 2024-2040

US$ Billions (real terms, 2024)



Source: Wood Mackenzie; Lens Upstream, Country Annual Cost

Abandonment requirements for offshore fields in Brazil total US$14.1 billion (real terms, 2023) from 2024-2040. The specific abandonment requirements differ based on the applicable fiscal regime.

Concession contracts carry an abandonment provision for SPT purposes. The provision is based on estimated decommissioning costs and is calculated on a straight-line basis over the life of the field. An estimate for decommissioning costs must be submitted and approved by the ANP as part of the field development plan. This value is divided by the expected life of the field and treated as a deduction from the SPT. Decommission cost estimates must be modified if development plans are updated. The abandonment provision is not deductible for corporate income tax es, but incurred decommissioning costs can be deducted for corporate income tax purposes.

The are no SPT applications for decommissioning expenses in PSCs. The government requires an abandonment guarantee upon first production in the form of a letter of credit, performance bond, or other support fund. Actual abandonment expense and associated indirect taxes are deductible for the corporate income tax and are recoverable as cost oil within the same PSC.

3.7. Operator Landscape

Petrobras dictates the direction of the industry and the overall operator landscape by virtue of its scale and inherent ownership advantages. The NOC is the largest resource holder and producer in Brazil, responsible for 65% of remaining commercial liquids resources and 67% of current offshore production.

The company benefits from holding a monopoly historically, legacy access, and possessing state-equity rights in pre-salt and other strategically significant resources. However, advantaged resource access is not the only attribute. Petrobras is a proven operator that has benefited from its own technological advances to aid development and unlock formerly sub-commercial resources.

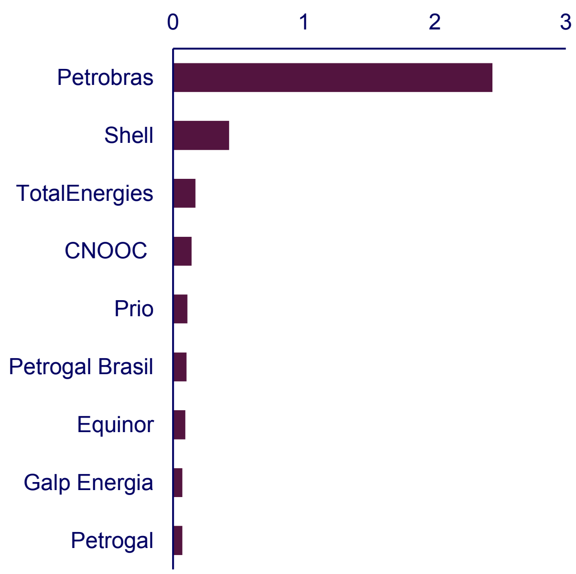
While Petrobras is the dominant player in the market, the scale of resource potential attracts many of the largest and most diversified oil and gas companies in the world. Multiple Euromajors, the US Majors, and Chinese NOCs all operate in Brazil. Resource scale, relative stability, and an established supply chain create a suitable environment for capital allocation within large diversified upstream portfolios.

Petrobras initiated a large-scale divestiture program in 2015 (see Section 3.8.) partially to refocus on the exploration and development of pre-salt reserves. This included paring back its international portfolio, but it also provided an opportunity for niche Independents to acquire mature producing fields offshore. The result was to allow access to newer entrants that add modest degrees of diversification to the overall sector.

Karoon Energy purchased assets Bauna in 2019 as part of the Petrobras divestiture program. The acquisition added to Karoon's portfolio with assets in Neon and Goia fields in the Santos basin.

Brazil Top 10 Companies by Forecast 2024 Production

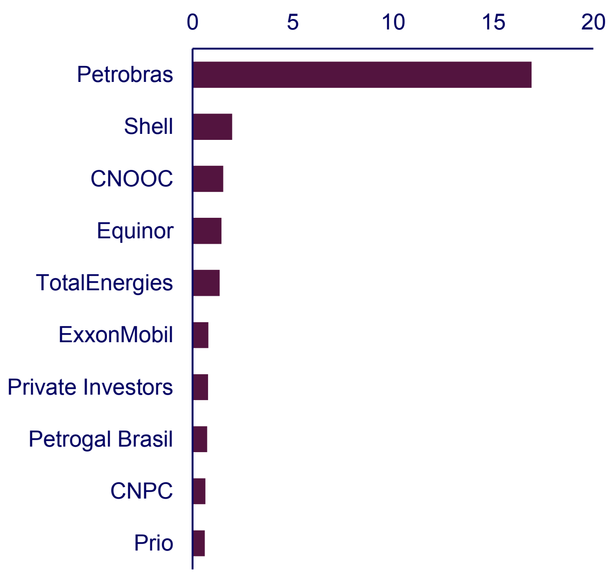
Million Boe/d



Source: Wood Mackenzie; Lens Upstream

Brazil Top 10 Companies by Remaining Commercial Offshore Liquid Resources

Billion Boe



Source: Wood Mackenzie; Lens Upstream

Past investments and ongoing development and licensing interest from established sector leaders reinforce the stature and attractiveness of the Brazilian offshore sector in the global upstream landscape.

Key Producers in Brazil

- **Shell** committed to the Brazilian deepwater market with its US$82 billion acquisition of BG Group in 2015; Shell has since established itself as the largest private producer and resource holder in Brazil; deepwater pre-salt development is a core focus of Shell's global upstream portfolio
- **TotalEnergies** is involved in the development and production in the core pre-salt polygon area that the Brazilian government has deemed to be strategically important. It also has operated production assets in the Campos basin. It also holds exploration acreage in outer portions of both the Campos and Santos basins
- **CNOOC** invested heavily in non-operated interests in established pre-salt fields, including the giant Buzios and Mero fields. Spurred by the success and learnings from its non-operated investments, CNOOC acquired its first operated block in 2022 (100% interest)
- **Equinor** considers deepwater as its most important growth theme, and opportunities in Brazil are integral to its strategy and growth ambitions. Equinor has sanctioned operated developments offshore Brazil in both 2022 and 2023. Both fields are anticipated to come online in the mid-2020s, creating further production growth. Equinor previously acquired a 25% interest in Roncador, the largest Campos basin field, for over US$2.8 billion in 2018
- **ExxonMobil** built large a pre-salt exploration portfolio through active bidding across multiple license rounds, but exploration efforts to date have yielded little success. Still, the company has invested heavily in Brazil in recent years and challenged assertions that it will stop exploring offshore Brazil
- **Chevron** demonstrated keen interest in Brazil in the recent December 2023 concession license round. Chevron was the largest spender in the auction, topping Petrobras and CNOOC to claim its first operated positions in Brazil with 15 blocks in the Pelotas Basin and nine blocks in the Santos basin
- **BP** has narrowed the focus of its upstream portfolio but continues to hold and add exploration blocks in high-impact areas in Brazil and plans additional frontier exploration drilling in 2024
- **Repsol-Sinopec Brasil** is a joint venture between Repsol and Sinopec Group with non-operating holdings across large producing fields as well as pre-salt exploration blocks. Each partner in the JV also has additional non-operational holdings in Brazil outside of the JV

Petrobras' divestment program also changed Brazil's corporate landscape by enabling new Independent operators to enter the market and begin harvesting cash from mature assets. These operators are also allowed to focus on redevelopment in areas that had not been higher priorities for capital allocation in Petrobras' portfolio. These operators include Enauta, PetroRio, 3R Petroleum, Petrogal, and Karoon.

3.8. Brazilian Transaction Activity

Brazilian offshore M&A has predominantly been driven by Petrobras' divestiture program. Petrobras initiated a large-scale divestiture program in 2015 to prioritize deleveraging and generate proceeds to fund additional pre-salt developments. Petrobras has divested over US$40 billion in assets since 2015.

Petrobras' remaining divestiture program is slowing and some assets initially contemplated for sale have been removed from the market with Petrobras is investing in the redevelopment of some mature fields. Petrobras is ultimately employing a stragey similar to the Independents that purchased assets from it as part of the divestiture program.

Brazilian Upstream M&A Activity

Announcement	Buyer	Seller	Consideration (US$MM)	Type
25 Dec 2023	Enauta	QatarEnergy	150	Asset - Package
28 Dec 2022	PetroReconcavo	Maha Energy	138	Asset - Package
01 Sep 2022	Prio	Dommo Energia	180	Corporate - Takeover
27 Apr 2022	Prio	Petrobras	2,203	Asset - Single
23 Feb 2022	Seacrest Capital	Petrobras	478	Asset - Package
31 Jan 2022	3R Petroleum	Petrobras	1,380	Asset - Package
23 Dec 2021	ACS Group	Petrobras	1,100	Asset - Package
12 Jul 2021	3R Petroleum	Petrobras	105	Asset - Single
30 Jun 2021	Petromais Global	Petrobras	300	Asset - Package
24 Feb 2021	PetroReconcavo	Petrobras	135	Asset - Package
17 Dec 2020	3R Petroleum	Petrobras	250	Asset - Package
19 Nov 2020	Prio	BP	100	Asset - Package
28 Nov 2019	Prio	Petrobras	100	Asset - Single
21 Oct 2019	Ecopetrol	Shell	105	Asset - Package
09 Aug 2019	3R Petroleum	Petrobras	191	Asset - Package
24 Jun 2019	Karoon Energy	Petrobras	665	Asset - Package
Total			**7,480**	

Source: Wood Mackenzie; M&A Tool, Brazilian deals >US$100 million; Karoon consideration includes the additional US$285mm contingent payment

3.9. Brazilian Emissions Summary

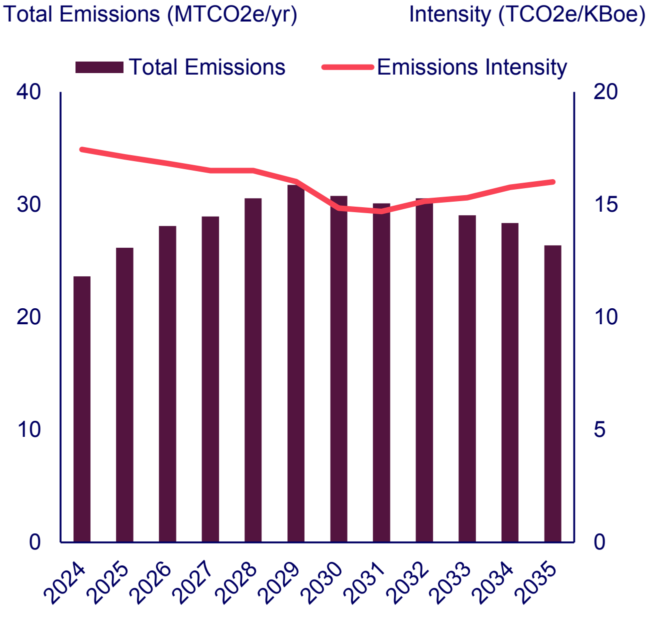
This section sets forth Woodmac's forecasts and acquisitions for Brazilian and certain other countries' offshore emissions through 2035.

Brazil's absolute Scope 1 & 2 emissions from offshore oil and gas operations are high based on the overall scale of offshore production. Brazil does benefit from productive deepwater resources as fields with high EUR per well tend to have lower emissions intensity.

Absolute Scope 1 & 2 emissions will continue to grow through the remainder of the decade as output continues to grow. Overall productivity coupled with widespread corporate initiatives on reducing emissions drive a downward trend in overall intensity until commercial production begins to decline post-2030.

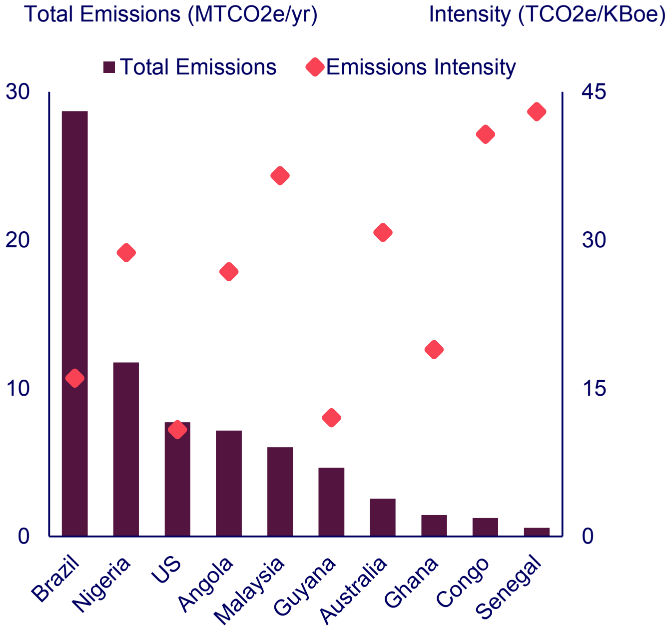
On an average intensity basis, Brazil does possess a favourable profile compared to the other largest deepwater liquids producing countries. The overall scale and per well EUR support a competitive Scope 1 & 2 emissions intensity and highlight a key aspect contributing to the overall competitiveness of Brazilian offshore resources.

Brazil Offshore Emissions Summary



Source: Wood Mackenzie; Emissions Benchmarking Tool Scope 1 & 2 emissions only; Deepwater and Shallow water

Offshore Liquids Producers (Average 2024-2035)



Source: Wood Mackenzie; Emissions Benchmarking Tool Scope 1 & 2 emissions only; Emissions across all water depths, but the country list was determined by the leading deepwater producers that employ development concepts most similar to Karoon's assets

In late 2023, Petrobras announced that it would install the first fully electrified FPSO in the country in 2025. The electric production platform represents steps and initiatives that Brazil's largest operator is taking to reduce absolute emissions. It is also working on gas reinjection at the seabed as opposed to reinjecting from the surface facility. These actions represent incremental steps and advances that can be implemented to further aid emissions reduction.

4. US GoM Market Background and Dynamics

The US GoM is an advantaged oil basin due to an attractive and stable fiscal regime, established infrastructure, more cost-efficient development opportunities, and low emissions intensity. US GoM oil and gas production is mature relative to other deepwater producing basins globally. As such, recent discovered volumes are lower than more frontier areas, but infrastructure led exploration (ILX) opportunities create modest, and quicker and lower-cost resource commercialization opportunities.

4.1. US GoM Summary

US GoM Upstream Key Facts

Remaining Commercial Offshore Liquids Resources	8.1 Billion barrels of oil equivalent
Liquids production (2024 expected)	2.1 Millions of barrels per day
Liquid reserves / production	10.6 years
Remaining Commercial Offshore Gas Resources	1.1 Billion barrels of oil equivalent
Gas production (2024 expected)	0.4 Million of barrels per day
Gas reserves / production	8.4 years

The US GoM is an important component of both the overall US oil and gas industry and the global deepwater marketplace. The US GoM, across both shallow water and deepwater, is expected to account for approximately 17% of total US oil production in 2024. Deepwater production in the region represents 25% of deepwater oil production globally.

Unlike many other basins, the US GoM holds a wide distribution of resources throughout the stratigraphy of the basin. Each producing unit contains enough petroleum resource to be a significant province on its own. Overall, the deepwater Miocene, Pliocene, and Pleistocene reservoirs contain one of the largest concentration of oil in the world.

Offshore production in the GoM is established and proven. Exploration and production activities began on the outer continental shelf in the 1950s. Production reached over 1 million barrels per day by 1971. As offshore production grew, interest, investment, and technological advances grew. Majors like Shell, BP, and Exxon drove the shift to deepwater waters in the 1980s. Deepwater production first occurred in 1988 and, in the late 1990s, deepwater production surpassed shallow water production.

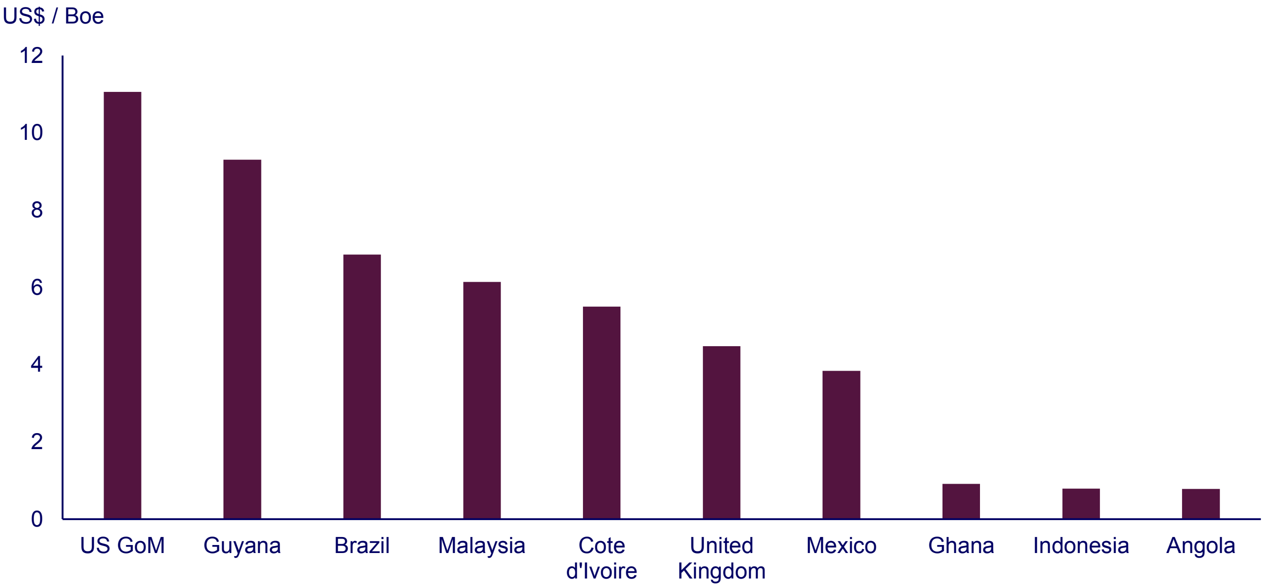
Widespread development across both the shelf and deepwater prompted an expansive network of production platforms and pipelines that support commercialization. This foundation promotes ILX, a quicker, cost-effective, and lower risk development strategy suited for smaller complimentary discoveries.

The US GoM is one the highest demand regions globally for latest generation floating drilling rigs. Advances in drillship technology have made higher pressure exploration more possible. These rigs are capable of completing wells in ultra-high pressure fields that contribute to visible nearer term production growth. However, the higher demand also pressures rig day rates that pressure economic targets.

Collectively, operators in the US GoM deepwater benefit from a variety of factors that coalesce to help make produced barrels among the most valuable barrels in the world on the basis of net present value per Boe of commercial reserves. These factors primarily consist of resource prospectivity, fiscal attractiveness and stability, and an infrastructure network that facilitates clearer commercialization opportunities.

As such, the US GoM holds the highest per barrel value of any deepwater region in the world in terms of project NPV per recoverable commercial resource at Woodmac's long-term US$65/bbl Brent (real terms, 2023) economic assumption. US GoM barrels are very competitive globally, and become more competitive as prices increase based on a flat royalty rate.

Global Deepwater Development Value (Full-development cycle NPV 10 divided by commercial resources)

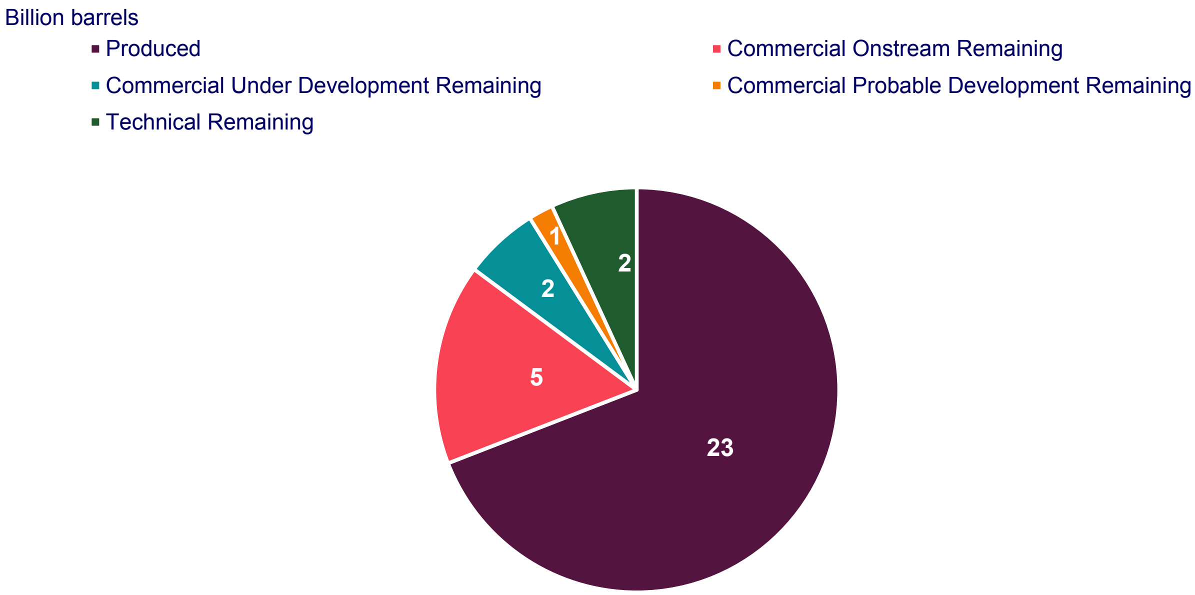


Source: Wood Mackenzie; Top level field developments, sanctioned from 2010-2023; deepwater developments with recoverable resource > 20 million Boe; hydrocarbon type is oil or oil & gas (gas only developments excluded)

4.2. US GoM Resource and Production Forecasts

Major deepwater discoveries and consistent large scale developments have contributed to steady deepwater production growth over the past 30+ years. ILX development strategies are expected to increase the commerciality of current reserves and new ultra high-pressure drilling technology holds the potential to unlock and replenish declining reserves through new discoveries.

US GoM Remaining Commercial Offshore Liquids Resources



Source: Wood Mackenzie; Lens Upstream, Country Reserves

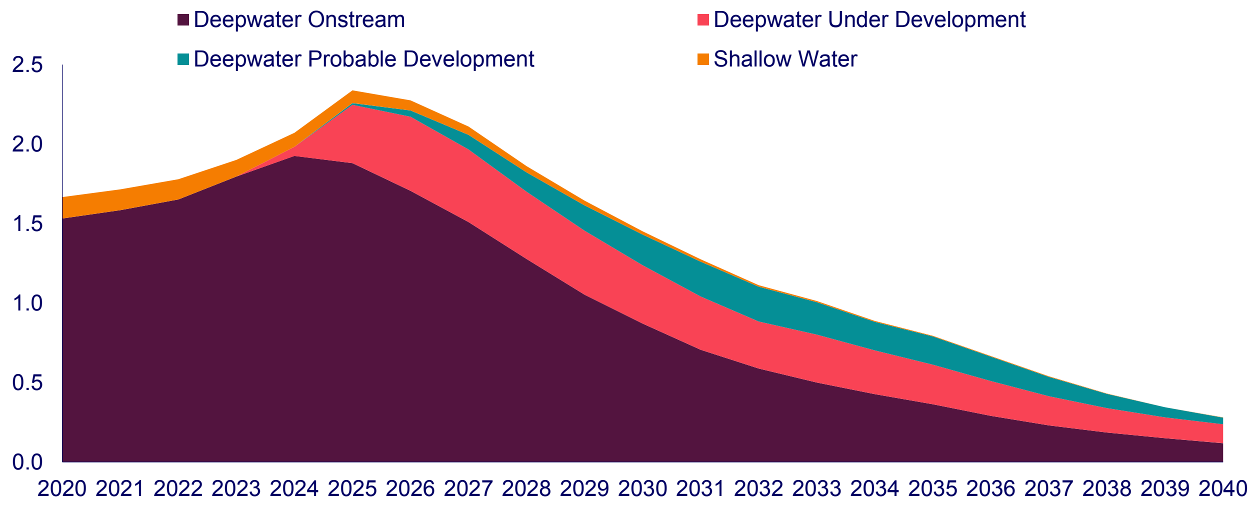
Over 23 billion barrels of liquids have been produced to date from reserves in the US GoM. This scale of produced volumes underscores why the US GoM is an established leader in the global offshore marketplace. 53% of this total produced resources are from shallow water and 48% from deepwater. However, 97% of the 5 billion barrels of commercial onstream remaining resources are in deepwater fields, highlighting the shift to deeper waters.

The region is more mature than many frontier deepwater basins, but remaining commercial reserves currently under development still hold another 2 billion liquids barrels. An additional 2 billion barrels of technical resources have been identified, but are not currently commercial based on infrastructure limitations and high-costs. All of the resources under development and 99% of technical resources are located in deep waters.

The discussion below sets forth Woodmac's forecasts and expectations for US GoM offshore liquids productions and capex through 2040.

US GoM Commercial Offshore Liquids Production, 2020-2040

Millions of barrels per day



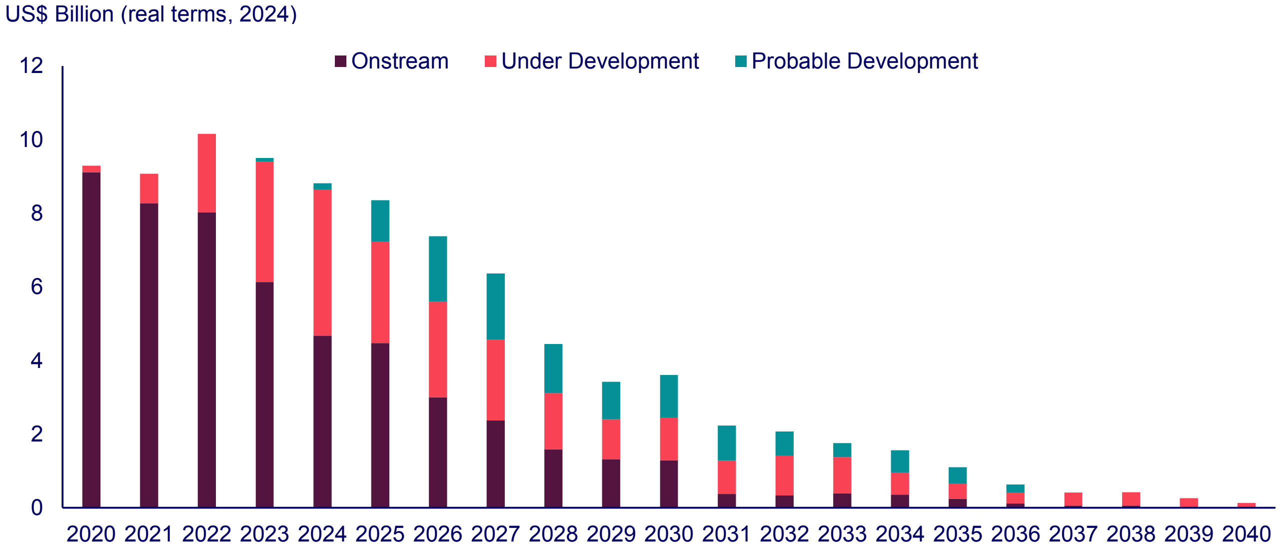
Source: Wood Mackenzie; Lens Upstream, Field Annual Production

The US GoM is expected to account for 8% of all offshore liquids produced globally in 2024, and 25% of deepwater liquids globally. US GoM deepwater liquids production reached an all-time high in 2023 at 1.8 million barrels per day. That is set to increase by another 10% to nearly 2.0 million barrels per day in 2024. Commercial projects onstream and sanctioned provide visibility to exceed 2.0 million barrels per day through 2027.

Demand for rigs in the US GoM drives costs up and has slowed the pace of development. That slowing does contribute to declines after 2025 as onstream production declines and the sanctioned projects do not offset base declines. Smaller fields have been commercialized through subsea tie-backs, but those incremental reserves also have not offset production declines. Exploration drilling is currently averaging around 20-25 wells per year.

More remote parts of the US GoM region do contain discoveries under appraisal that represent projects where future development is probable.

US GOM Commercial Offshore Capex (Excluding Abandonment) by Development Status



Source: Wood Mackenzie; Lens Upstream, Country Annual Cost

The commercial capital spend mirrors the production outlook. Lower cost subsea tieback present opportunities for incremental capital and production growth, but will not fully offset declines. Rig demand in the US GoM is very high, leading to competitive contracting and escalating day rates. Higher service costs spur some project delays or even project cancellations.

In 2023, 97% of total capital expenditures and 100% of capital expenditures for assets under development were in deepwater. Probable developments are also solely deepwater.

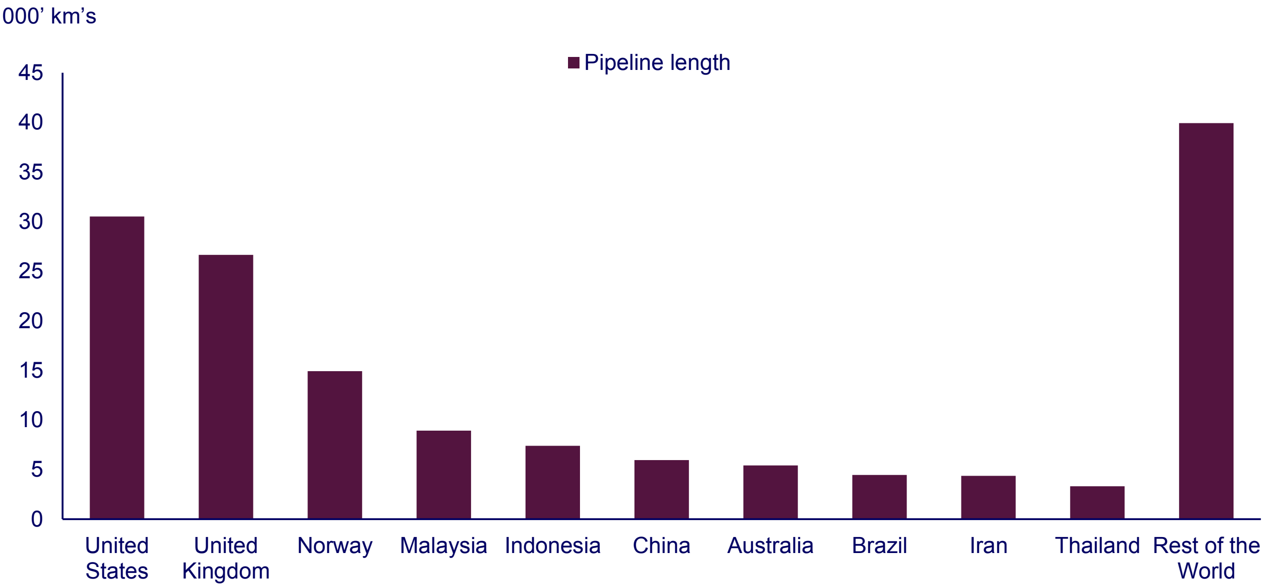
4.3. US GoM Infrastructure Summary

Pipeline infrastructure and hub processing facilities support the development of offshore resources in the US GoM. The US GoM possesses more operational offshore production platforms than any other country (Section 2.6). To accompany those production platforms, an extensive network of pipeline infrastructure has been developed across the region over the course of the past 40 years. The pipeline network developed on the continental shelf, but the discovery of deepwater resources in the late-1980s/early-1990s led to major pipeline corridors across the Gulf.

Large-scale shallow water production facilities in the 1970s and 1980s were installed to produce and process shelf reserves. As those fields matured and declined, deepwater resources were discovered and developed. To facilitate deepwater opportunities, legacy shelf platforms were converted into hub facilities to service the newer deepwater fields. Deepwater production facilities in the US GoM are being designed with excess processing capacity to facilitate the development of smaller fields in the vicinity in the future.

Many of the largest commercial developments in the US GoM, like Thunder Horse, Mad Dog, and Atlantis, were contingent on the development of purpose-built pipeline to enable these deepwater fields to be tied back into the existing shelf infrastructure.

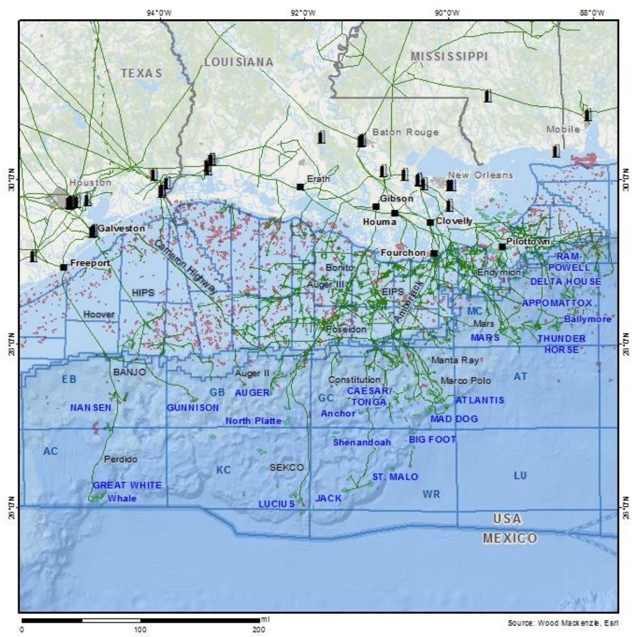
Commissioned Offshore Pipelines by Country



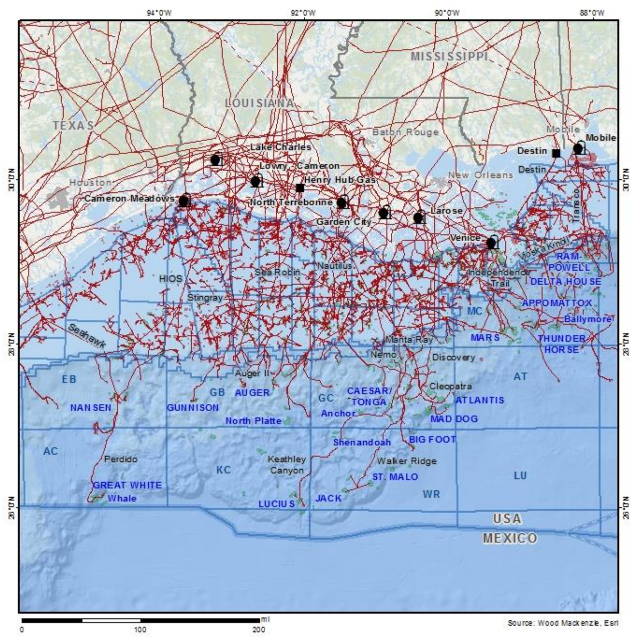
Source: Wood Mackenzie

Over 30,000 km's of pipeline are commissioned throughout the US GoM, representing 20% of all offshore pipeline installations offshore in terms of length. Expansive systems in the US GoM support the transportation of both oil and gas. The US government's no-flare policy in federal waters and reluctance to sanction offshore loading drive the use of pipeline transportation. Midstream infrastructure continues to expand to support ongoing production growth in the region.

Regional Map: Deepwater Oil Pipeline Systems



Regional Map: Deepwater Gas Pipeline Systems



Source: Wood Mackenzie

Trunk lines on the Continental Shelf deliver deepwater production to refineries and other major pipeline hubs along the Texas and Louisiana coastlines. Industrial demand centers and a large refining complex in the region provide a mature market for US GoM resources. The US Gulf Coast represents one of the world's most concentrated refining centers.

The US Gulf Coast is also a major hub for the petrochemical industry. All of these attributes function together to create an operating environment that requires and encourages investment in oil and gas infrastructure.

Well-developed infrastructure in the region extends to a robust service sector, led by deepwater drilling rigs. The US GoM possesses the second most contracted floating drilling rigs behind Brazil. Over 18% of contracted floating rigs globally are operating in the US GoM. Similar to Brazil, all of these rigs are high-specification sixth, seventh, or eight generation floating rigs. The fact that all contracted rigs are the newer and more in demand rigs is evidence that US GoM operators are willing to pay a higher premium to secure the most technologically advanced options in the global rig fleet. Overall, fleet utilization in the US GoM is 92% compared to a global average of 74% for sixth, seventh, and eight generation deepwater drilling rigs.

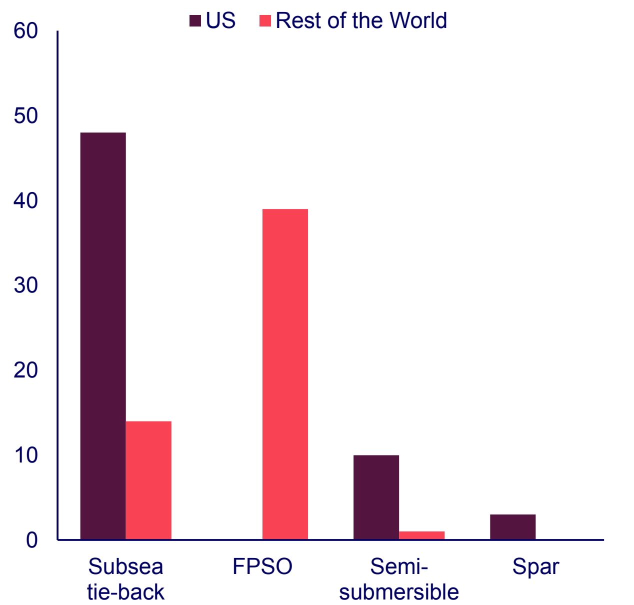
4.4. Infrastructure-Led Exploration (ILX)

Existing infrastructure in mature areas provides attractive opportunities for ILX and subsequent developments. The US GoM is particularly suited for an ILX business model based on numerous factors. The region possesses a long history of exploration with more available seismic and well data to better inform exploration decisions. Historically, regular lease sales coupled with small block sizes created access opportunities. A wide range of prospect types creates opportunities for a diverse set of operators with different specialties and business strategies.

The result of de-risked and better understood reservoirs with existing infrastructure in place is higher commercial success rates, shorter lead times, and clearer paths to commercialization. The size of ILX discoveries tend to be more modest, but remain competitive on a per barrel basis because of the cost and timing advantages provided by ILX. There is a proven track record of cost-efficient ILX creating value in the US GoM.

Deepwater Project Sanctions by Field Development

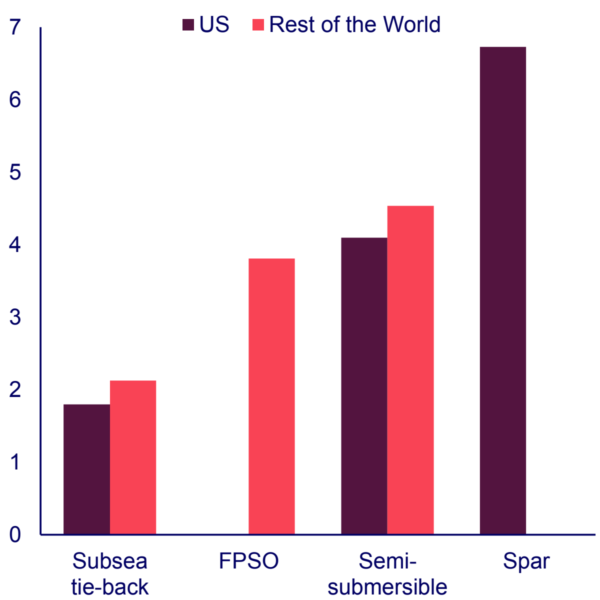
Number of projects



Source: Wood Mackenzie; Liquids focused projects (top-level) sanctioned from 2016-2023; deepwater only

FID to First Production

Number of Years

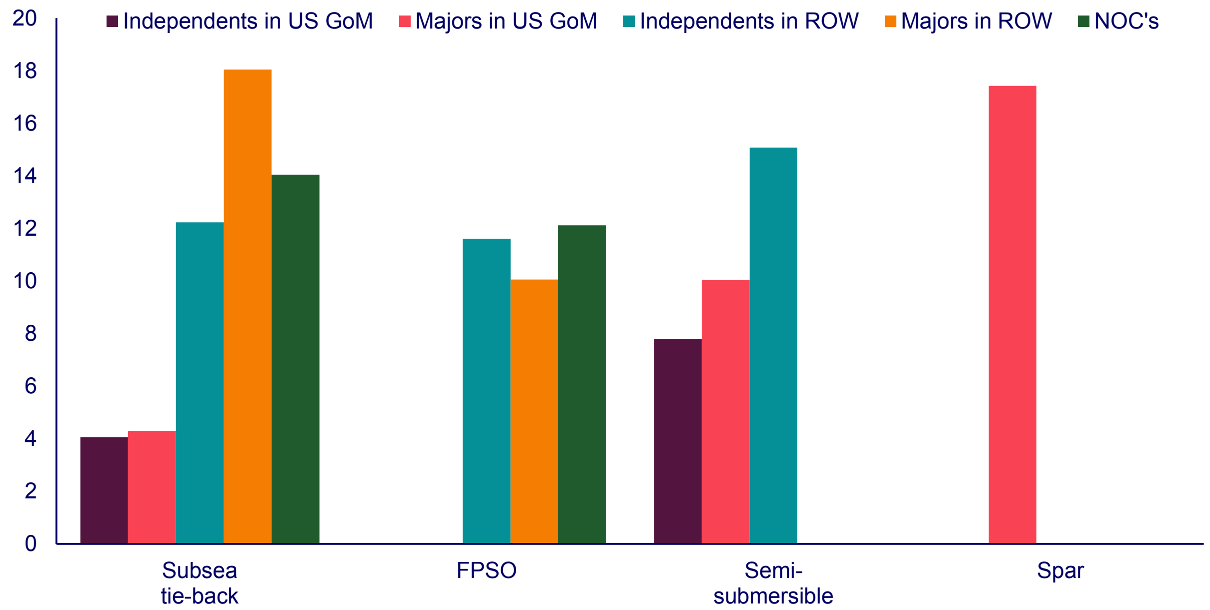


Source: Wood Mackenzie; Liquids focused projects (top-level) sanctioned from 2016-2023; deepwater only

ILX is most often commercialized by subsea tiebacks into existing production facilities. The number of operational production facilities in the US GoM provide more opportunities for subsea tiebacks. From 2010-2023, 61 or 53% of commercially sanctioned liquids-focused deepwater projects occurred in the US GoM. Out of those 61 project sanctions, 79% of those projects were developed via subsea tiebacks to existing production facilities already in place. Leveraging existing production facilities creates time and cost advantages. US GoM subsea tiebacks offer the fastest time to first production of any deepwater field development solution.

Discovery to First Production

Number of Years



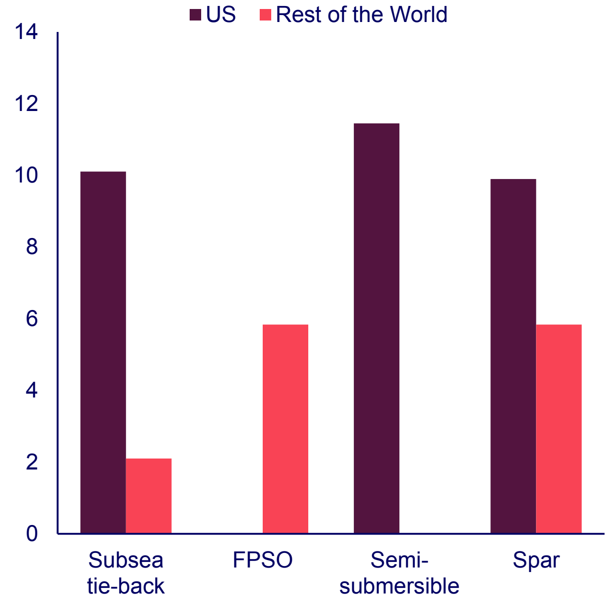
Source: Wood Mackenzie; Liquids focused projects (top-level) sanctioned from 2016-2023; deepwater only

ILX enables faster development times once an investment decision has been made, but it also enables faster overall cycle times (time from discovery to first production) because the presence of existing infrastructure allows producers to make quicker investment decisions. Less time is needed to assess development requirements because the existing infrastructure is already known.

Additionally, Independents in the US GoM exhibit the quickest overall cycle times. More tieback opportunities in the US GoM promote faster cycle times, but the Independents are also more nimble and adaptable. LLOG, the operator of the US GoM assets that Karoon purchased, is an example of a US GoM focused specialists with short proven cycle times.

Per Unit Development Value by Field Development

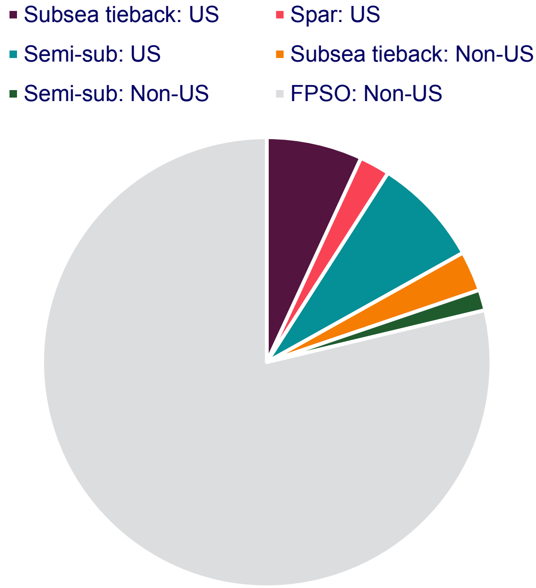
Development NPV / Commercial Boe (US$/Boe)



Source: Wood Mackenzie; Liquids focused projects (top-level) sanctioned from 2016-2023; deepwater only

Commercial Resources by Field Development

Billion Boe



Source: Wood Mackenzie; Liquids focused projects (top-level) sanctioned from 2016-2023; deepwater only

4.5. US GoM Fiscal Summary

The fiscal regime for offshore leases in the US GoM is characterized by straight-forward concession terms, a low relative tax burden, and fiscal stability. The US fiscal regime has made oil in the US GoM among the most advantaged barrels in the world.

Leases are awarded by the federal government under concession terms comprised of two key elements: a fixed-fee royalty and federal income tax. Royalty is charged at a fixed rate on wellhead value at the lease level. The rate ranges from 12.5% to 18.75% depending on water depth. Federal Income Tax is levied at 21% and charged at the company level, rather than the lease level.

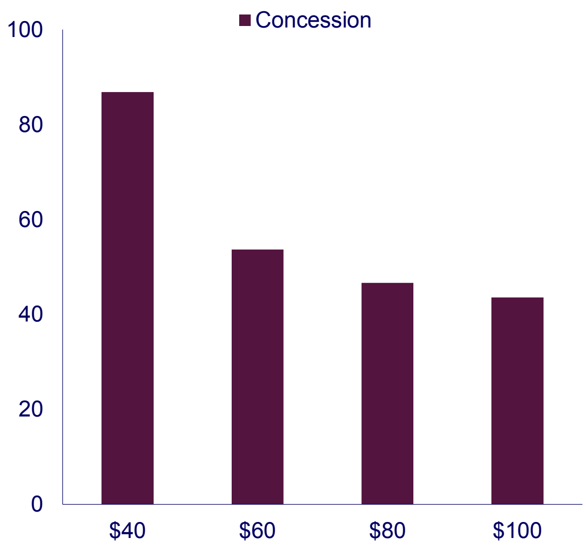
Signature bonuses are biddable items in US offshore licensing rounds. Historically, average winning bids approached US$100 million. Minimum bids are on a per acres basis, US$25/acre for shallow water and US$100/acre for deepwater bids.

The government take for new awards in this fiscal model is proportional at all levels of production. Depreciation derived from development costs can reduce the Federal Income Tax, reducing the risk in exploration and development. No other mechanisms are in place to reduce the tax burden on new leases. Royalty Suspension Volumes (RSVs) were eliminated in 2010, but are still active for leases licensed before then.

Fiscal policy in the US GoM has a history of stability. In recent years, the changes have included step changes to the royalty rate and a reduction to RSVs. The most notable change effecting offshore leases was the Jobs Act in 2017 that reduced the Federal Income Tax from 35% to 21% for all companies operating in the US.

Government Share by Oil Price Sensitivity

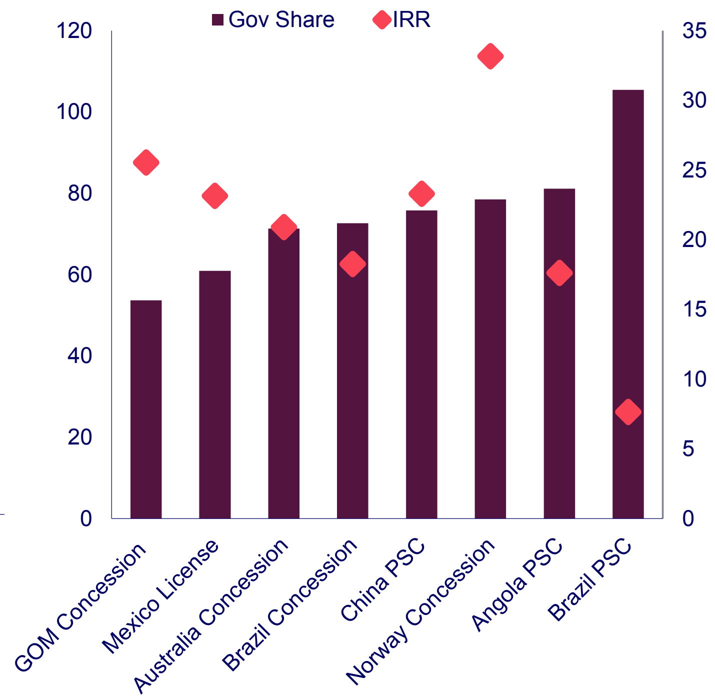
% (Government take / pre-share NPV)



Source: Wood Mackenzie, Fiscal Benchmarking Tool
Medium Deepwater Field (200mmbbl), Medium Costs

Government Share vs Investor IRR

% (Government take / pre-share NPV) & Investor IRR



Source: Wood Mackenzie, Lens Upstream, US$60 Brent Price

The US GoM historically is recognized for overall fiscal stability and lower political risk compared to other offshore regions. The taxation system and royalty rates have evolved over time, but the underlying concessionary regime and structure has been consistent as activity and production in the region has grown and matured. Political actions rarely impact the US GoM on its own, outside of extraordinary events like the 2010 Macondo oil spill.

In January 2021, the federal government paused oil and gas leasing on federal lands, both onshore and offshore. After legal action was taken, the US court system ruled that the Bureau of Ocean Energy Management (BOEM) was to proceed with the previously planned lease sale. Since that action, operators have responded to subsequent lease sales with a large amount of combined bids to acquire leases and derisk any potential permanent bans in the future. That risk was tempered with the 2022 Inflation Reduction Act which restored lease sales and capped the deepwater royalty rate at 18.75% for the next ten years.

A new 5-year federal lease sale plan for 2024-2029 was released in late 2023. The plan only outlines three offshore lease sales compared to ten in the previous 5-year leasing program. This represents a curtailment in leasing activity compared to fairly consistent lease sales going back multiple decades. Three more recent lease sales were all interrupted or rescheduled due to litigation.

Persistent risks and opposition to new oil and gas development create uncertainty regarding future lease sales. Increased bidding activity in Lease Sale 261 (December 2023) indicates that companies are responding to future uncertainty by placing a premium on acquiring licenses for exploration while available to retain additional organic growth optionality.

Risks to future leasing and the associated impact on exploration are present and will remain politically divisive. Political rhetoric has also aimed at outright bans on drilling on federal land, including offshore waters. This has not garnered any tangible traction and is not seen as a risk at present.

4.6. US GoM Government Revenues

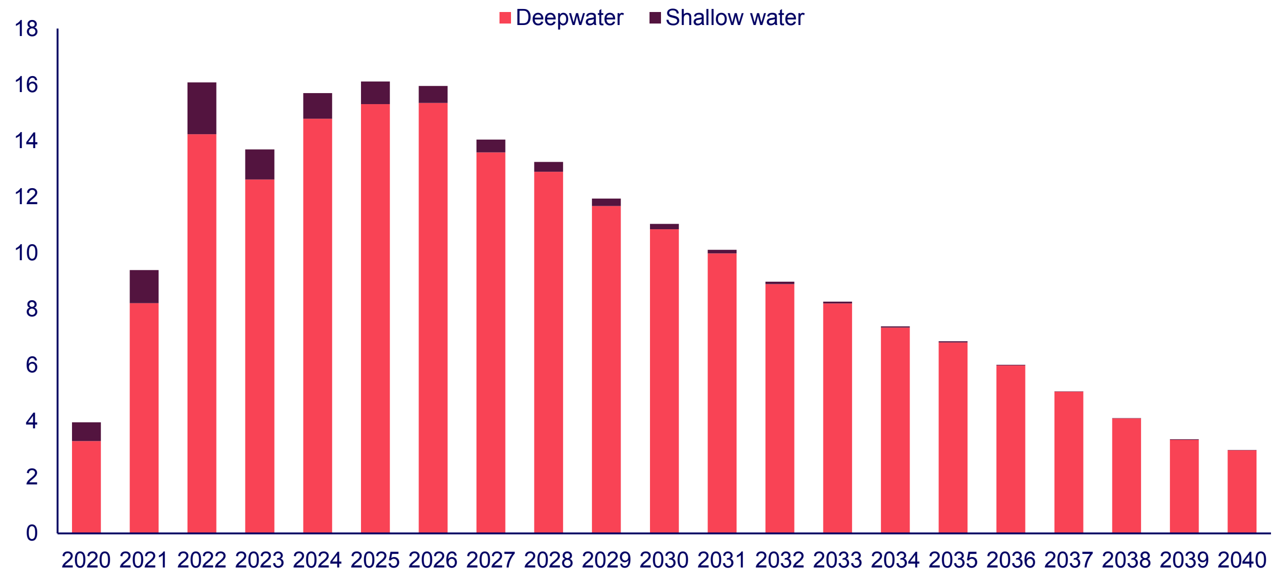
The oil and gas industry is a important contributor to the broader US economy. The oil and gas industry in the US supports 10.3 million jobs and is responsible for 8% of the gross domestic product[10]. The oil and gas sector in the GoM region directly employs 350,000 people and contributes $30 billion to the country's gross domestic product[4].

In 2023, the US federal government collected US$4.4 trillion in tax revenue from all sources[11]. US GoM offshore production contributed US$14 billion in direct tax revenue. That doesn't take into account other indirect taxes associated with oil and gas operations across the region.

The table below sets forth Woodmac's forecasts and expectations regarding US GoM government revenues through 2040.

US Government Revenues from US GOM Oil and Gas Activity

US$ Billion (nominal terms)



Source: Wood Mackenzie; Lens Upstream, Country Annual Royalty and Government Take

Government revenues are closely tied to production with flat royalty and corporate income tax rates. Revenues are expected to follow production and capital expenditure forecasts.

4.7. US GoM Abandonment Requirements

Decommissioning in the US GoM is regulated by the US federal government. No cash abandonment fund is required, but surety bonds are required of US$0.5M for each lease, a single areawide US$3M bond, and supplemental bonding as determined by the BOEM. Abandonment costs cannot be carried back to apply against other taxes, but can be ring fenced for income tax deductions at the company level.

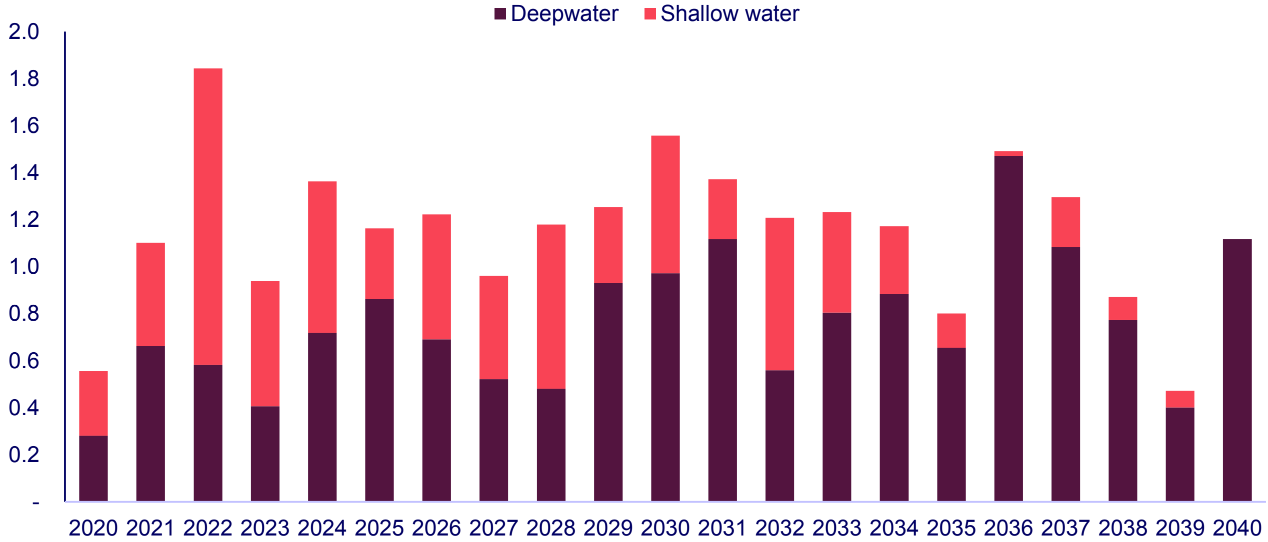
The US also has a provision that a company cannot completely remove its decommissioning liability with the sale of an asset. If the purchasing company orphans the well without proper abandonment, the liability can revert to the seller.
The table below sets forth Woodmac's forecasts and expectations for US GoM offshore abandonment capex through 2040.

[10] Source: US Treasury Fiscal Data

[11] Source: American Petroleum Institute Fact Sheet

US GOM Commercial Offshore Abandonment Capital Expenditures, 2024-2040

US$ Billions (real terms, 2024)



Source: Wood Mackenzie; Lens Upstream, Country Annual Cost

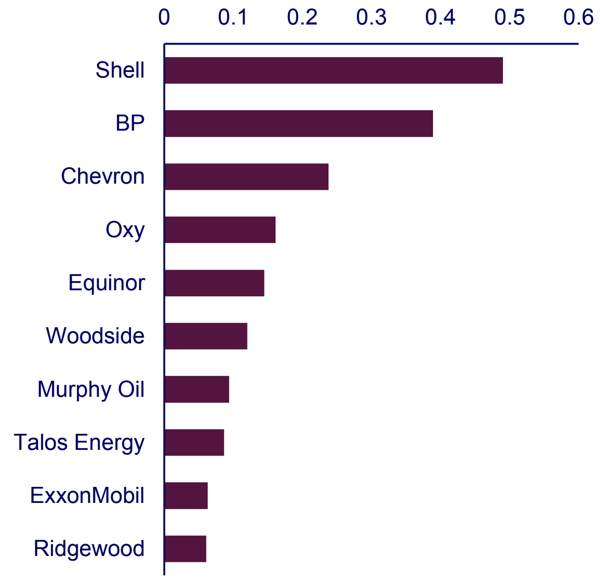
4.8. US GoM Operator Landscape

Discovered resource volumes, an attractive fiscal regime, and established infrastructure network combine to create a supportive investment environment. Low emissions intensity (discussed further in Section 4.10) further elevates the overall competitiveness of the US GoM.

Because it is a competive region, numerous large oil and gas producers hold the US GoM as core components of their upstream portfolios. Majors led the exploration and development of deepwater resources in the US GoM and continue to hold substantial positions. Large independendents and niche US GoM specialists have also established strong presences and defined strategies.

US GOM Top 10 Companies by 2024 Production

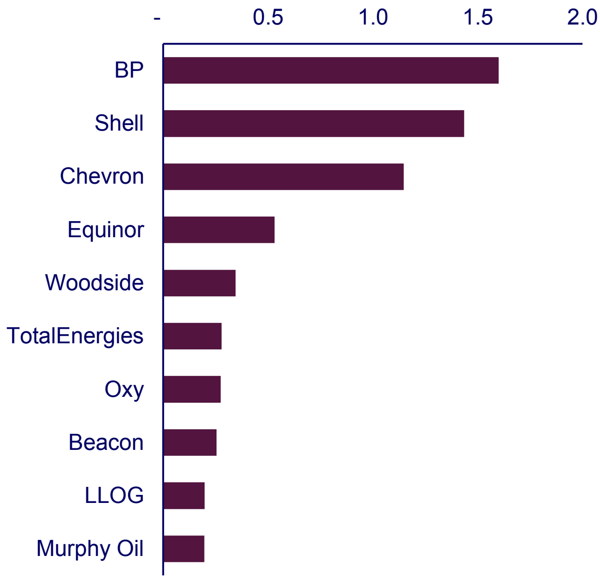
Million Boe/d



Source: Wood Mackenzie; Lens Upstream

US GOM Top 10 Companies by Remaining Commercial Offshore Liquid Resources

Billion Boe



Source: Wood Mackenzie; Lens Upstream

Most of the globally diversified oil and gas majors have operating history and scale in the US GoM. Long-standing commitment to the region by leading producers underscores the attractiveness of the region. Consistent overlap in a single region among a group of competitors that possess diversified upstream portfolios all across the globe conveys a consensus on the overall competitiveness.

Major Oil Companies

- **Shell** is the largest producer in the GoM, due in part to the company's focus on high-grading its portfolio and significant investment in production facilities. Shell made its first investment in ultra-high pressure development in 2022
- **BP** holds the highest volume of reserves and follows closely behind Shell in production. The company's portfolio is weighted to deepwater and near-field drilling. New management recently reiterated the importance of US GoM Paleogene development to its overall upstream objectives
- **Chevron** sanctioned its first ultra-high pressure field in 2019. The company is the third highest producer and continues to grow in the region
- **Equinor** has signalled a focus on asset quality with disposal of many low producing areas in recent years. The GoM continues to be at the core of the company's portfolio optimization
- **ExxonMobil** has distinguished itself from other Majors by not including the GoM as a core area of its portfolio. The company is still one of the top ten producers, but there is no expectation of organic growth in reserves or production
- **TotalEnergies** holds a significant presence in the GoM, generally through non-operational holdings. The sale of ultra-high pressure assets to Shell in 2022 signaled a shift away from the region

Beyond the Majors, several large, diversified Independents and niche GoM specialists have demonstrated success. Smaller Independents have also translated exploration success into commercial developments by leveraging existing infrastructure to de-risk development opportunities.

Independent Operators

- **Occidental Petroleum (Oxy)** acquired a large portfolio position in the GoM with the acquisition of Anadarko in 2019. The region has been in more maintenance mode since the acquisition, but Oxy was active in the most recent lease sale, signaling interest in future exploration

- **Murphy Oil**'s largest producing asset in its portfolio is the GoM. The company has a backlog of quick, low-cost redevelopment opportunities that will provide organic growth when completed
- **Talos Energy** is focused solely on the GoM and continues to actively build scale through US GoM focused corporate acquisitions of other US GoM specialists. The company is also one of the first entrants into the GoM Carbon Capture, Utilization and Storage (CCUS) space (recently announced to be sold to TotalEnergies for US$148 million)
- **Woodside**'s merger with BHP has strengthened the company's near field and greenfield project pipeline and provided the financial strength to take advantage of the opportunities in the GoM

In the GoM, there has been an increase in holdings and production among smaller Independents and private equity backed operators. LLOG Exploration, QuarterNorth (recently announced to be acquired by Talos), and Ridgewood are examples of niche GoM specialists. A notable strategy currently being used by niche operators is growth via ILX. This helps offset some of the scale and capitalization challenges that would preclude these more specialized, niche operators from investing in large, longer lead time developments. These Independents have also demonstrated more streamlined decision making and greater overall nimbleness to bring projects online quick, which ultimately brings more value forward (See FID to First Production Cycle Times by Peer Group in Section 4.4).

4.9. US GoM Transaction History

M&A activity remained light in 2023, with announced deals remaining below US$1 billion. Despite that, there were three new entrants to the basin: Westlawn, Alta Mar Energy, and Karoon Energy. Other GoM focused deals were driven by private operators.

Much of the recent transaction history involves more specialist Independents that either seek to continue building scale, or successful explorationists that then monetize a portion of the subsequent commercial development opportunity.

US GoM Upstream M&A Activity

Announcement	Buyer	Seller	Consideration (US$MM)	Type
15 Jan 2024	Talos Energy	QuarterNorth Energy	1,290	Corporate
26 Nov 2023	Karoon Energy	LLOG	720	Asset – Package
12 Jul 2023	Multiply Group	Breakwater Energy	100	Corporate
22 Sep 2022	Talos Energy	EnVen	1,089	Corporate
17 Aug 2021	Woodside	BHP	14,713	Asset – Package
02 Feb 2021	Eni and partners	ExxonMobil	126	Asset – Package
05 Oct 2020	BHP	Hess Corporation	505	Asset – Single
01 Jul 2019	Talos Energy	Castex Energy	640	Asset – Package
27 Jun 2019	W&T Offshore	ExxonMobil	200	Asset – Package
23 Apr 2019	Murphy Oil	LLOG	1,375	Asset – Package
11 Apr 2019	Equinor	Shell	965	Asset – Package
17 Sep 2018	Kosmos Energy	Deep Gulf Energy	1,225	Corporate
18 Jun 2018	Cox Oil	Energy XXI	374	Corporate
07 Mar 2018	TotalEnergies / Shell	Cobalt	520	Asset – Package
15 Feb 2018	Fieldwood Energy	Noble Energy	499	Asset – Package
Total			**23,305**	

Source: Wood Mackenzie; M&A Tool, US GoM deals >US$100 million; note, only includes deals where the US GoM value represented at least 50% of the overall deal value

4.10. US GoM Emissions Profile

Oil production from the US Deepwater GOM has the lowest carbon emissions intensity when comparing against offshore liquid themes globally. The US Deepwater GoM achieves its carbon advantage from a combination of legacy infrastructure, operator policy, low gas content, and federal regulation.

The recent focus of operators in the GoM to seek higher returns and managed spending has resulted in fewer wells drilled per barrel of production. This combined with the fact that the US GoM naturally has some of the lowest Gas to

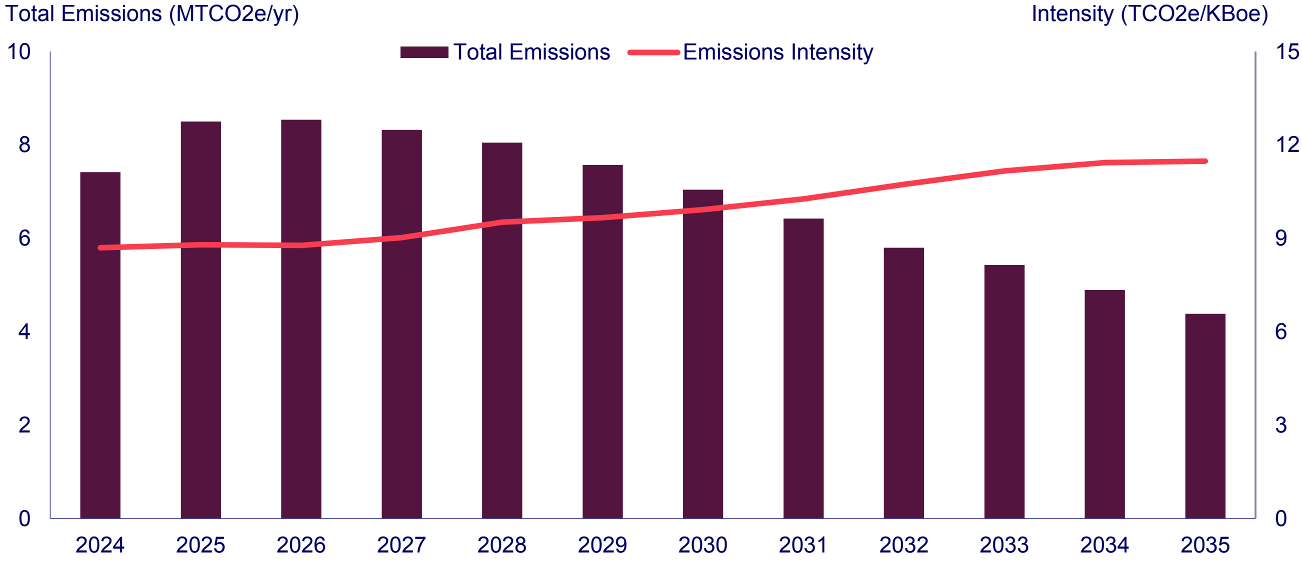
Oil Ratios (GOR) in the world means operators produce less emissions per barrel of production compared to other liquid themes across the world.

Operators in most areas in the GoM have easy access to an extensive network of infrastructure that enables efficient transportation to refineries on shore. A well connected and commercial market for gas incentivizes companies to prioritize reducing unintended gas emissions.

US federal regulations are more strict on emissions than other comparable themes and give enough incentives for takeaway infrastructure buildout. Any intentional flaring or venting in the GoM must be approved by the Bureau of Safety and Environmental Enforcement (BSEE) prior to any action and permits are only available in emergency cases. The large portion of production by Majors and large Independents with a publicly stated focus on ESG and public scrutiny provides intangible incentive to avoid any chance of an environmental incident.

The table below sets forth Woodmac's forecasts and expectations for US GoM deepwater emissions through 2040.

US GOM Deepwater Emissions Summary



Source: Wood Mackenzie; Emissions Benchmarking Tool

4.11. US Gulf Coast CCUS Potential

US GoM operations possess advantaged emissions profiles, but proximity to CCUS along the Texas and Louisiana Gulf Coasts provides additional opportunities for further emissions reduction. The US GoM region has been and will continue to be key for CCUS development due to its many sequestration sites, supportive policies, existing onshore and offshore pipelines, and proximity to industrial emissions.

The enhanced federal 45Q tax credit has significantly improved economics for projects. Revised 45Q provisions allow for up to US$85 per ton for carbon capture and secure underground storage, making CCUS projects more financially viable. Furthermore, the bipartisan Inflation Reduction Act added US$12 billion in funding for CCUS initiatives. This highlights federal-level commitments to the technology and solution.

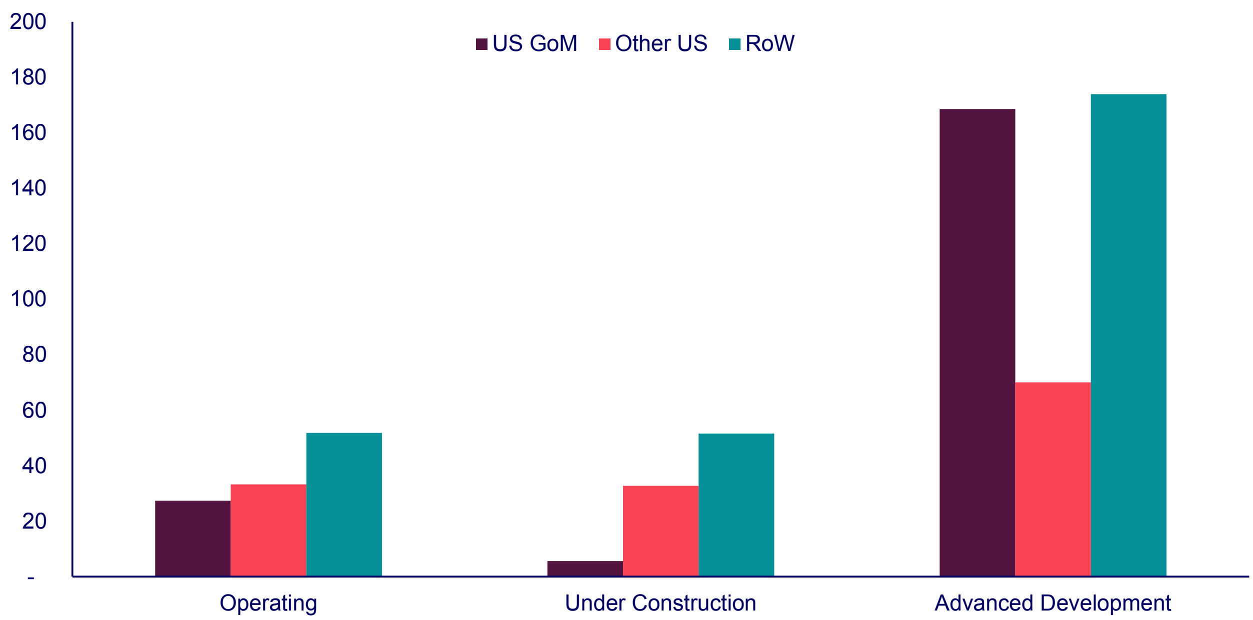
State-level support in Texas and Louisiana complement these federal incentives. Both states offer programs for transferring the long-term liability of stored CO_2 to the state. Texas is actively working to obtain primary enforcement authority (primacy) for Class VI wells, while Louisiana has recently been granted this authority. Class VI wells inject CO_2 into deep rock formations for long-term underground storage. States can seek primary enforcement authority (primacy) over Class VI wells if they meet the EPA's guidelines. The primary benefit is a quicker approval period.

Federal and state incentives, existing infrastructure and accommodating CCUS reservoirs position the US GoM region as one of the most advanced and prospective markets for CCUS development. Many operators in the region have leveraged existing subsurface knowledge to participate in the CCUS value chain. Independent US GoM specialists, like Talos Energy, have created complimentary CCUS business segments targeting CCUS-as-a-service. Talos' recent US$148 miilion sale of its CCUS business to a Major TotalEnergies (announced March 18, 2024) further validates the monetization strategy and regional opportunity.

Overall, the US GoM region possesses the highest concentration of operating, under construction, or advanced development sites in terms of annual sequestration capacity. This highlights additional opportunities that US GoM operators have to further reduce emissions or participate in the CCUS value chain through partnerships.

CCUS Capacity by Development Status

Annual Project Capacity (Mtpa)



Source: Wood Mackenzie; Lens Carbon

5. Conclusion

Karoon's 2023 entry into the US GoM deepwater market complements its existing offshore operations in Brazil, acquired in 2019. Karoon's strategic decisions position its upstream portfolio in two established and active offshore markets.

Offshore Brazil and the US GoM represent lower-risk offshore markets for a variety of reasons:

- Resource and production scale, especially for liquids. This includes global leadership in discovered liquids volumes this century
- Supportive and stable concessionary fiscal regimes (Brazil has both concession and PSC terms, with Karoon's assets are subject to the more investor friendly concessionary terms)
- Established infrastructure, service sectors, and supply chains that support development and high activity levels
- A credible and proven operator mix consisting of Majors, NOCs, large-diversified Independents, and regional specialists
- Competitive Scope 1 & 2 emission profiles relative to other resource themes

Karoon's portfolio benefits from its underlying exposure to established and advantaged oil-rich provinces. All of the attributes in each region combine to create viable and more sustainable operating environments for producers.

6. Appendix

6.1. Glossary

Abandonment: Removal of the production facilities on a field or play following the end of production.

Basin: An area of depression in the earth's crust where sediments accumulate. A geological basin is an area of sedimentary deposition, which has maintained a relatively homogenous structural identity over time.

Breakeven: The oil or gas price at which the remaining present value of a chosen asset equals zero at a selected discount rate and date.

Capital Expenditures (Capex): Expenditure by companies on capital equipment. These include, where appropriate, costs for production facilities, processing equipment, subsea facilities, development drilling, pipelines, offshore loading facilities, terminals, any 'other' capital costs, and finally any abandonment costs.

Carbon Capture, Utilization and Storage (CCUS): Capture of carbon dioxide emissions resulting from the combustion of fossil fuels, and subsequent storage of this CO2 under ground, in a disused oil or gas field, or a saline aquifer.

Commercial Development: A project is commercial when the essential social, environmental and economic conditions are met and it is highly likely to be developed. This includes political, legal, regulatory and contractual conditions. While five years is recommended as a time frame for development, this could be extended. For example, when the producer defers development for market-related reasons, or to meet contractual or strategic objectives.

Concession: A licence awarded to a company for a defined area and time which generally gives the company the right to explore, develop, produce and sell hydrocarbons that it finds. In return for this concession, the host government receives an area rental and taxation, which may comprise royalty, income tax and additional petroleum-specific taxations.

Deepwater: defined as fields located in a water depth of over 400 metres.

Development costs: Capital costs incurred after a decision has been taken to develop a field, including the costs of development drilling, platforms, pipelines, and other capital equipment.

Dutch Title Transfer Facility (TTF): The leading pricing hub for gas markets in Europe. Up to 2014 the UK's NBP was the most significant pricing hub in Europe.

Emissions Intensity: A measurement of emissions on a per unit of production basis.

Estimated ultimate recovery (EUR): Estimated ultimate recovery (EUR) is the sum of liquids (crude and condensate), and natural gas liquids (as a specified barrel per thousand cubic feet ratio in the gas stream) expected to be recovered over the total life of the well in each play.

Exploration and Appraisal (E&A): E&A refers to the range of activities leading up to and following a new hydrocarbon discovery, but prior to development activities. Exploration can include seismic acquisition and processing, regional and local geophysical studies, gravity and magnetic surveys, plus all wells drilled up to and including the initial discovery well. Subsequent work to assess the size and commerciality of a new discovery is classed as appraisal activity.

Exploration and Production (E&P): The upstream portion of the oil and gas industry which incorporates the exploration for and production of crude oil and natural gas.

FID: Final investment decision (FID) is taken by the operator and partners of a development. It is the moment at which they commit to spending money on a field's development and is purely an internal decision.

Fiscal Regime: A representation of a fiscal system governed by tax law and/or specific contracts such as production sharing contracts.

Henry Hub: The main pricing point in the US gas market. It is a pipeline interchange on the Sabine pipeline (linking nine interstate and four intrastate pipelines) near Erath in Louisiana. Prices in most locations in the US are indexed at an expressed differential to the Henry Hub. It is the standard delivery point for the NYMEX natural gas futures contracts and the OTC swaps (including basis) traded on Intercontinental Exchange (ICE).

Independent: A company that is focused on the exploration for and production of crude oil and natural gas. Usually relatively small in size compared to companies that integrate these activities with transportation, refining and marketing of hydrocarbons.

Infrastructure: Processing and transportation facilities that are used to bring hydrocarbons to market e.g. production platforms and pipelines.

Internal rate of return (IRR): The rate of return at which the discounted income equals the discounted costs (the discount rate when the net present value equals zero). In our Exploration tool, this is a full-cycle metric and reflects the return on exploration activity, taking into account the full costs of exploration.

Japan Spot: The benchamark used by Wood Mackenzie for LNG imports to the Asia market.

Liquified Natural Gas (LNG): LNG is formed by cooling natural gas (largely methane) to -163° C (-260° F) at which point the gas condenses into a liquid. As a Wood Mackenzie field classification, the LNG project type is defined as fields which supply, or have the potential to supply, gas to LNG plants.

Major: Large integrated oil company with a business combining the exploration for and production of hydrocarbons with transportation refining and marketing activities. The Majors include: Eni, Shell, TotalEnergies, BP, Chevron, ExxonMobil, and Equinor.

National Oil Company (NOC): An oil company that is controlled by a state. Most state-controlled companies are included in the national oil company (NOC) peer group.

OECD: An international economic organisation of 34 countries founded in 1961 to stimulate economic progress and world trade.

Offshore: That geographic area that lies seaward of the coastline. In general, the coastline is the line of ordinary low water along with that portion of the coast that is in direct contact with the open sea or the line marking the seaward limit of inland water.

Onstream: Equivalent to On Production as defined by the Society of Petroleum Engineers PRMS guidelines. The development project is currently producing and selling petroleum to market.

OPEC: A group of 12 petroleum exporting countries. The member states of OPEC are: Algeria, Congo, Equitorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, the United Arab Emirates and Venezuela.

Operating Expenditures (Opex): The day-to-day costs incurred in producing oil and gas. These include, where appropriate, personnel costs, costs of materials and supplies, fixed and variable costs for field operations, transportation (non-tariff), leasing, insurance and G&A. Additionally, they include any tariffs paid to other assets for transportation and/or processing production.

Operator: Company which manages the asset (well, field, licence or transportation facilities) on behalf of the participants. The lead oil company in the joint venture which owns the field. The operator's role is to co-ordinate a programme of oil exploration and development of its licensed area(s) on behalf of its co-licensees (if any).

Probable Development: Equivalent to Justified for Development as defined by the Society of Petroleum Engineers PRMS guidelines. The development project is justified based on reasonable commercial conditions forecast at the time of reporting and reasonable expectations that all necessary approvals and contracts will be obtained.

Probable Reserves: Defined by the Society of Petroleum Engineers as unproved reserves that analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves. Proved plus probable reserves are often referred to as 2P reserves.

PSC: An agreement between a contractor and a host government whereby the contractor typically bears all risk and costs. In return, if exploration is successful, the contractor is given the opportunity to recover the investment from production. Once these costs are covered, the state and the company split the rest of the production based on agreed percentage division.

PSC Cost Recovery: Under the terms of a PSC, contractors pay all exploration, development and operating costs. The contractor recovers these costs from a percentage of production in each accounting period. The process is known as cost recovery.

PSC Profit Share: Proportion of annual production remaining after cost recovery by the contractor (and royalty if applicable).

Real Terms: Refers to the way that a cost or cash flow is presented. Real terms cash flows are presented as of a specified date with actual expected cash flows adjusted to take out the impact of inflation.

Recoverable Reserves: Equivalent to reserves. Proved plus probable oil, gas, condensate and LPG reserves.

Regulatory Regime: The laws and government regulations governing the oil and gas industry within a country.

Remaining NPV/Boe: The remaining NPV of the company at the end of the year divided by the closing reserves.

Remaining Reserves: Equivalent to reserves. In our upstream data tools, this refers to the volume of recoverable reserves remaining at the discount date.

Reserves/Resources: Quantities of petroleum anticipated to be commercially recoverable by a development project. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of a given date) based on the development project(s).

Resource Potential: Resource potential is a measure of the productive potential of the play if all the accessible and prospective land is drilled and produced based on a reasonable assumption of well spacing. There are no economic or time constraints applied in the model to calculate this volume. The resource potential does not include oil or gas already produced or classified as commercial.

Rig, Floating Rig, Drill ship: A generic term for the machinery and/or installation used to drill a well.

Royalty: Payments that may be made to the government or licence owner in return for the producer having access to hydrocarbons or minerals. It is generally paid as the first use of any revenue, and is usually quoted as a percentage of gross revenue.

Scope 1: Emissions include direct emissions from operations.

Scope 2: Indirect emissions from purchased electricity.

Shallow Water: Wood Mackenzie field water depth classification: defined as fields located in a water depth of over 0 metres and less than 400 metres.

Signature Bonus: Upfront payment to the government to secure a licence.

SPT: Special petroleum tax is a tax, applicable only to the petroleum industry, that is designed to generate an additional share of revenue, or profit, for the government.

State Equity: State entity (usually the NOC) takes an equity interest in the IOC consortium.

Under Development: We use the term 'under development' to refer to an asset (field, play, oil refinery, LNG plant, LNG project, LNG regas, LNG ship or pipeline) which has received development approval, but not yet started production.

6.2. Economic Assumptions

Woodmac's price assumptions ("Economic Assumptions") are distinct from our price forecasts. Economic assumptions are used in our asset valuations, while price forecasts are created by our markets services.

Economic assumptions comprise of price decks used in our research products for asset valuation purposes. Economic assumptions reflect an average of the last 30 days of the forward curve for the first 36 months, and then revert to a long-term real price which is based on the prices we believe is the level where assets transact between willing buyers and sellers. Woodmac's current long-term economic assumption is US$65/bbl Brent (real, 2024 terms) with annual inflation at 2%.

The implied long-term real Brent oil price (ILTOP) is a proprietary deliverable in our M&A service. It is used as a guide to derive our long-term Brent oil price assumption. ILTOP is the real Brent price required for our NPV 10 valuation of commercial assets traded to equal the actual deal consideration.

Price forecasts represent expectations for market prices based on analysis of supply and demand fundamentals by our Macro Oils and Regional / Global gas teams. Breakeven prices for marginal supply and other fiscal and economic considerations help guide the determination of price forecasts.

Summary of Wood Mackenzie Economic Assumptions (Q1 2024)

Year	Brent Price (US$/bbl, nominal)	Henry Hub Price (US$/mcf, nominal)	Inflation (%)
2024	83.80	3.61	2.46
2025	78.90	4.15	2.00
2026	75.50	4.18	2.00
2027	68.98	3.72	2.00
2028	70.36	3.79	2.00
2029	71.77	3.86	2.00
2030	73.20	3.94	2.00
2031	74.67	4.02	2.00
2032	76.16	4.10	2.00
2033	77.68	4.18	2.00
2034	79.24	4.27	2.00
2035	80.82	4.35	2.00
2036	82.44	4.44	2.00
2037	84.09	4.53	2.00
2038	85.77	4.62	2.00
2039	87.48	4.71	2.00
2040	89.23	4.80	2.00
Long-term (real)	**65.00**	**3.50**	**2.00**

Disclaimer

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REMUNERATION REPORT

SECTION 1. LETTER FROM THE CHAIR OF THE PEOPLE AND CULTURE COMMITTEE

Dear Shareholders,

On behalf of the People and Culture Committee and the Board of Directors I am pleased to present the Karoon Energy Ltd Remuneration Report for the six months ending 31 December 2023.

Throughout the Remuneration Report the term 'Transition Year 2023' refers to the six months ending 31 December 2023, which has been referred to as 'TY23' in previous ASX releases.

In this report we have also sought to maintain and, where possible, enhance our goal of ensuring the Remuneration Report is based on a high level of disclosure and transparency.

The TY23 period was a transformational time for Karoon with a major production acquisition being identified, assessed and completed, continuing focus on Baúna achieving production and operational improvements and progression of detailed analysis of the Neon discovery. With a significant list of strategic goals being addressed in TY23, Karoon's team has risen to the challenge maintaining the focus on outcomes and progress. The Karoon team is committed to the Company's strategic goals and has performed very well in busy and complex circumstances, for which the Committee and Board thanks them.

As we transition from a 30 June to 31 December reporting date, we have implemented the following one-off changes to our incentive programs for this six month period (TY23):

- TY23 short term incentive (STI) offers – Participants were assessed over the six month period as opposed to the usual 12 month performance period, against the Corporate Scorecard and where appropriate, role-specific objectives. Following the Board's assessment of Company performance for the six month performance period against a 12 month scorecard, it has exercised discretion to award the full year outcome for some metrics where the 12 month targets were achieved in full within TY23. All participants' TY23 STI outcomes were however capped at 50% of the usual STI opportunity and therefore no individual received an outcome greater than 50% of their full year STI maximum opportunity.
- TY23 long term incentive (LTI) grants – LTI opportunity levels were granted on a pro-rated basis to reflect the six month period as opposed to the usual 12 month financial period, with no change to the length of the three year performance period, starting from 1 July 2023.

For both plans, participants will be eligible for their usual annual STI and LTI opportunity from 1 January 2024 as we move to a 31 December reporting date in 2024, subject to the achievement of performance conditions.

TY23 Performance and Remuneration Outcomes

Karoon's strategy and remuneration structure is designed to firmly and transparently link remuneration outcomes to shareholder value.

We believe that long term shareholder value has been significantly enhanced during TY23 across a variety of the key corporate metrics as a result of the transformational acquisition of a 30% interest in a material, value accretive producing asset, being the Who Dat, Dome Patrol and Abilene oil and gas fields, associated infrastructure and various interests in the adjacent exploration acreage in the deepwater offshore US Gulf of Mexico (GoM). This transaction also positions Karoon well for potential further growth in the GoM.

Our other key operational and financial highlights for TY23 included:

- Continuing to have the highest safety standards is our highest priority. No recordable personal safety, Lost Time Injury or Tier 1 and 2 Process Safety incidents were reported during TY23. Our total recordable injury rate of 0, compared to 0.4 in FY23, resulted in stretch outcomes being attained in the Corporate Scorecard.
- Delivering Baúna Project production of 5.4 MMbbl, which falls above the middle of our guidance range of 4.5-6.0 MMbbl.
- Ensuring prudent cost control in our business by outperforming on our stretch production cost target of US$60.3 million, with actual costs at US$58.9 million.

- Delivering an underlying net profit after tax of US$144.7 million in six months compared to US$145.9 million in the 12 months to June 2023.
- Entering into a new 5 year revolving reserve-based lending facility with a syndicate of banks, which will support Karoon's ongoing operations and help fund future growth opportunities.
- Executing a binding agreement to purchase verified carbon units from the Hiwi REDD+ forest conservation project, located in north-western Brazil, which along with existing carbon credits, would allow us to fully offset Scope 1 and 2 emissions for FY23. Our aim is for the Who Dat acquisition to be carbon neutral for Scope 1 and 2 emissions on an equity share basis within five years of purchase, noting our Baúna Project was carbon neutral in FY21 and FY22 and we are on track to be carbon neutral in FY23.

In determining the remuneration outcomes for employees and executives, the Board has considered the overall strategic performance of Karoon as well as individual performance outcomes having regard to the specific objectives set at the beginning of TY23.

The TY23 remuneration outcomes were:

Fixed remuneration	2.0–3.1% increases	Fixed remuneration increases were provided to ensure that Karoon's remuneration levels remain competitive with the markets in which we operate, given we compete for talent globally: • Dr Julian Fowles, Chief Executive Officer and Managing Director (CEO/MD) received a 3.1% increase. • Mr Raymond Church, Executive Vice President & Chief Financial Officer (CFO) received an increase of 3.1%. • Mr Antonio Guimarães, Executive Vice President & President Karoon Brazil (EVP Brazil) received a 2.0% increase.
Short Term Incentive ('STI')	Corporate Scorecard outcome of 49% awarded	In the Board's approach towards assessing TY23 performance, it assessed the progress made by management in the six month performance period, against the 12 month scorecard. Due to Karoon's strong performance over some of the measures, the Board exercised discretion to award the full year outcome for some targets which were achieved in full within TY23. The Board has determined that 49% of the 12 month Corporate Scorecard component of the STI was achieved in TY23. This results in an individual STI outcome of 49% for the CEO/MD. For the CFO, who is also assessed against role-specific objectives (20% weighting), his overall STI outcome is 49.2%. 50% of the STI outcome will be deferred for one year in performance rights and the remaining 50% is payable in cash. See section 6 for more detail.
Long term Incentive ('LTI')	No LTI due for testing	No LTI awards were due for testing in TY23. The next LTI awards are due to be tested on 30 June 2024.

Other TY23 Changes

During the year, the following changes were made to the KMP group:

- At the 2023 AGM, Mr Peter Botten was appointed as the new Chair of Karoon Energy following the retirement of our previous Chair, Mr Bruce Phillips.
- Our EVP Brazil, Mr Antonio Guimarães, resigned his employment with the Company on 14 November 2023. Details of his outgoing remuneration arrangements are detailed in section 7.

There have been no changes to Non-Executive Director (NED) fees in TY23.

We hope you can join us at the 2024 AGM on 23 May 2024 and, as always, if you have any questions or comments please do let us know.

Yours sincerely

Mr Peter Turnbull, AM
Chair, People and Culture Committee

29 February 2024

SECTION 2. INTRODUCTION

The Board of Directors is pleased to provide Karoon's TY23 Remuneration Report, which details the remuneration for its KMP, defined as those persons having the authority and responsibility for planning, directing, and controlling, directly or indirectly, the activities of the Group.

For the TY23, KMP disclosed in the Remuneration Report are as follows:

Name	Position	Term As KMP
Executive Director		
Dr J Fowles	Chief Executive Officer and Managing Director (CEO/MD)	Full Period
Non-Executive Chairman		
Mr P Botten	Independent Non-Executive Chairman	Full Period – Chair from 23 November 2023
Mr B Phillips	Former Independent Non-Executive Chairman	Until 23 November 2023
Non-Executive Directors		
Ms L Rachid	Independent Non-Executive Director	Full Period
Mr C Davey	Independent Non-Executive Director	Full Period
Mr P Turnbull	Independent Non-Executive Director	Full Period
Mr T Fraga	Non-Executive Director	Full Period
Other KMP		
Mr R Church	Executive Vice President and Chief Financial Officer (CFO)	Full Period
Mr A Guimarães	Executive Vice President & President Karoon Brazil (EVP Brazil)	Until 14 November 2023

For the purposes of the Remuneration Report:

(i) 'Executive' means the CEO/MD and other KMP of the Group.

(ii) 'Fixed remuneration' has the meaning given in section 4.

(iii) 'Other benefits' has the meaning given in section 4.

(iv) 'Total remuneration' means fixed remuneration plus at-risk remuneration.

(v) 'At-risk remuneration' means STI and LTI.

The Remuneration Report for TY23 outlines the remuneration arrangements of KMP of the Group in accordance with the requirements of the *Corporations Act 2001* and its regulations. The information provided in this Remuneration Report has been audited by Karoon's external auditor, as required by Section 308(3C) of the *Corporations Act 2001*. The Remuneration Report forms part of this Directors' Report.

SECTION 3: REMUNERATION STRATEGY AND GUIDING PRINCIPLES

Karoon's guiding principles for its remuneration framework are as follows:

- **Prioritising safety, culture and ethics**: ensuring that clear vesting gateways exist based on appropriate safety and ethical outcomes. If outcomes do not meet the relevant standards, these gateways will block 'at-risk' remuneration payments, specifically the STI.
- **Generating shareholder value is paramount:**
  - Remuneration outcomes (particularly incentive-based outcomes) are designed to take account of share price movements across the performance period and therefore, the value delivered to shareholders.
  - A close alignment is created between operational performance, delivery of corporate objectives, rewards and sustained growth in shareholder value.
  - As Karoon has now transitioned from explorer to producer, it is recognised that capital management initiatives should also now be considered.

- **Attracting and retaining the best people:**
  - Our remuneration structures are designed to attract, motivate and retain the best people while remunerating them reasonably and competitively.
  - We encourage our people to hold equity in Karoon which builds a culture of viewing management decisions as an owner, thereby helping to further align executives' and shareholders' interests. Minimum shareholding policies apply to our executives and Directors.
  - Remuneration and people issues are considered by the People and Culture Committee of the Board and environmental and social issues by the Sustainability and Operational Risk Committee of the Board. Nonetheless, all relevant decision-making and associated discussion remains the responsibility of the Board.
- **Linking Environment, Social and Governance (ESG) measures to remuneration:** ESG considerations are integrated into our remuneration structures via our TY23 STI Corporate Scorecard.
- **Ensuring transparency:** remuneration measures, outcomes and reporting are as simple and transparent as possible for our shareholders and other stakeholders.

Board and People and Culture Committee Oversight

To assist in ensuring good remuneration governance at Karoon, the Board of Directors established a People and Culture Committee that provides detailed oversight and recommendations to the Board on remuneration and people related arrangements.

The People and Culture Committee currently consists entirely of independent Non-Executive Directors and is responsible for reviewing and making recommendations to the Board of Directors regarding (among other things):

- The quantum of sub-CEO executive remuneration.
- The sub-CEO executive remuneration framework, including the operation of, and performance-based outcomes under, Karoon's share-based incentive schemes.
- The recruitment, retention and termination policies and procedures for sub-CEO executives.

The Board of Directors, assisted by the People and Culture Committee, conducts remuneration reviews for its Non-Executive Chair, Non-Executive Directors, executives and all employees to ensure that remuneration settings remains market competitive, fair and aligned with both market practice and the best interests of shareholders.

The Board is responsible for all aspects of the remuneration of the CEO/MD.

Further information on the role and responsibilities of the People and Culture Committee is contained in the People and Culture Committee Charter, which can be found under the Governance tab on Karoon's website at www.karoonenergy.com.au.

Share Trading Policy

The trading of ordinary shares by Non-Executive Directors and executives is subject to, and conditional on, compliance with Karoon's Share Trading Policy.

Under Karoon's Share Trading Policy, an individual may not limit his or her exposure to risk in relation to securities (including performance rights). Directors and executives are prohibited from entering into any hedging arrangements over unvested share options or performance rights under Karoon's share-based remuneration schemes.

Karoon monitors compliance with its Share Trading Policy.

To gain approval to trade and ensure that trading restrictions are not in force, any employee, contractor or other designated person wishing to trade in Karoon securities must consult the Company Secretary, while the EVP Brazil, the Company Secretary or any Director wishing to trade in Karoon securities must consult the Chair, and the Chair must consult and seek approval of the Audit, Risk and Governance Committee Chair. All trades by Directors and executives during the financial period ended 31 December 2023 were conducted in compliance with Karoon's Share Trading Policy.

Karoon's Share Trading Policy can be found under the Governance tab on Karoon's website at www.karoonenergy.com.au.

SECTION 3: REMUNERATION STRATEGY AND GUIDING PRINCIPLES CONTINUED

How does Karoon make decisions about remuneration

The Board of Directors has developed a remuneration policy that ensures executive remuneration supports the current business strategy and needs of the business. In particular, the decision to use performance tested share-based remuneration (in addition to cash-based incentive payments) for its incentive plans reflects the Board of Directors' belief that this best aligns executive and shareholder interests in the short and long term. Karoon's success is measured by the delivery of its strategic objectives in the short term and a clear demonstration of shareholder value creation in the long term through share price growth.

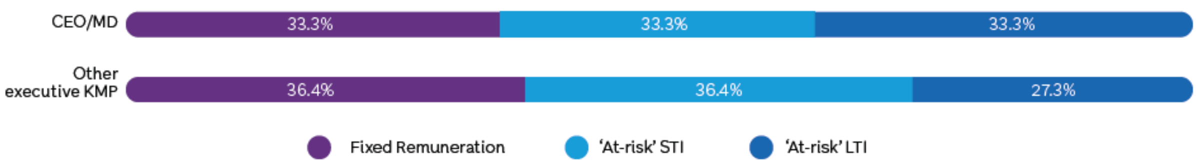
Broadly, the objectives of Karoon's executive remuneration framework are to ensure:

- Remuneration is reasonable and competitive in order to attract, retain and motivate talented and high calibre executives capable of managing Karoon's diverse international operations.
- Remuneration is set at a level acceptable to shareholders, having regard to Karoon's performance, and rewards individual achievements.
- Remuneration structures create alignment between performance, reward and sustained growth in shareholder value.
- Remuneration outcomes provide recognition of contribution to overall long term growth in the value of Karoon's asset portfolio and are transparent to both participants and shareholders.
- Remuneration incentivises the best possible outcomes for the broader stakeholder community, including fostering best practice in preventing bribery and/or corruption, along with driving sustainability and safety outcomes.

SECTION 4. EXECUTIVE REMUNERATION FRAMEWORK FOR TY23

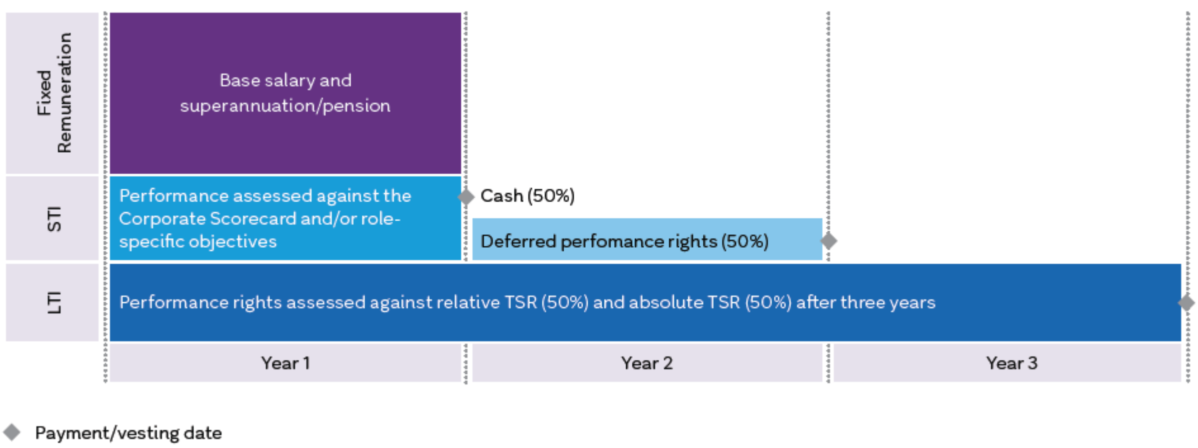
The following table summarises the remuneration mix for executives for TY23, based on maximum achievement of incentive plan outcomes. Each executive is eligible to receive fixed remuneration and at-risk remuneration (STI and LTI). The majority of the remuneration package is weighted towards at-risk remuneration, which is only received where performance conditions are met and is not guaranteed.

Annualised Remuneration Mix for TY23



Set out below is an illustration of our remuneration framework and a summary of the STI and LTI opportunity available to the executives.

	CEO/MD	CFO	EVP BRAZIL
STI OPPORTUNITY	100% of fixed remuneration	100% of fixed remuneration	100% of fixed remuneration
LTI OPPORTUNITY	100% of fixed remuneration	75% of fixed remuneration	75% of fixed remuneration



We have provided more detail on each element of remuneration below.

Fixed Remuneration

WHAT IS FIXED REMUNERATION?	Fixed remuneration consists of base salary and superannuation/pension contributions received. Other benefits not included in fixed remuneration include accruals of annual or long service leave, any salary sacrifice items or non-monetary benefits such as temporary allowances, health insurance, motor vehicles, expatriate travel, certain membership and associated fringe benefits tax, depending on each individual's respective employment arrangements ('Other Benefits'). Details of other benefits paid to executives are set out in full in section 10.
FIXED REMUNERATION CHANGES FOR TY23	As Karoon operates internationally in Brazil and most recently, has expanded into the USA, our fixed remuneration levels need to be competitive to attract and retain talent beyond Australian markets. Fixed remuneration of executives increased at the start of TY23, to ensure ongoing market competitiveness. Changes to fixed remuneration (per annum) were[1]: • CEO/MD – 3.1% increase from US$640,071 to US$653,192. • CFO – 3.1% increase from US$490,091 to US$500,138. • EVP Brazil – 2.0% increase from US$389,262 to US$397,050.

Superannuation/Pension Contributions

The CEO/MD receives fixed remuneration inclusive of superannuation contributions, above the maximum contributions cap. Other Australian executives of the Company received statutory superannuation contributions of 11% of salary up to the maximum statutory contribution.

The EVP Brazil receives an amount equal to 10% of monthly salary into a private pension fund.

Social Security and Indemnity Fund Contributions

Karoon's Brazilian based executives are subject to specific Brazilian employment regulations, whereby the Group is required to contribute 27.3% of salary to the Government's social security fund. These contributions are subject to a cap on an annual, calendar year basis. However, the executives on retirement will only be entitled to a portion of the contributions made. A further 8% of Brazil based executives' salary is required to be contributed to a Federal Severance Indemnity Fund ('FGTS'). In the situation of unfair dismissal without just cause, the Group would have to pay a fine equivalent to 50% of the accumulated balance of the individual's FGTS account.

'At risk' Remuneration

Karoon aims to align the interests of executives with those of shareholders by having a significant proportion of executive remuneration 'at risk' via the STI and LTI plans. 'At risk' remuneration represents the proportion of remuneration that requires pre-determined performance conditions to be met before the remuneration is vested to the executive. At the beginning of each financial year, the Board reviews the financial and operational goals and targets, looking broadly at where the building blocks for long term value exist, then sets performance conditions that generate a link between operating performance, remuneration received and the value created for shareholders.

1. Exchange rates of AU$/US$0.6535 and R$/US$0.2034 were used to convert from local currency.

SECTION 4. EXECUTIVE REMUNERATION FRAMEWORK FOR TY23 CONTINUED

STI Plan

WHO PARTICIPATES

Executives. Participation in the STI Plan is at the discretion of the Board of Directors on the recommendation of the People and Culture Committee.

PERFORMANCE PERIOD

For TY23, the performance period is six months – 1 July 2023 to 31 December 2023. The Corporate Scorecard and role specific objectives are set by the Board to reflect key priorities to build long term value. Details of the Corporate Scorecard are set out in section 6.

STI OPPORTUNITY

The STI opportunity level of each executive is a pre-determined proportion of an executive's fixed remuneration. In respect of the TY23 award, the board have assessed performance for the six months based on the 12 month scorecard, which was set at the start of the performance period, commencing 1 July 2023. The CEO/MD can earn up to 50% of his fixed remuneration (usual annual opportunity is 100% of fixed remuneration). The CFO and EVP Brazil can earn up to 50% of fixed remuneration (usual annual opportunity is 100% of fixed remuneration).

The calculation of the TY23 award can be illustrated as follows:

[Fixed Remuneration (at 1 July 2023) x Annual STI opportunity] x Outcome of performance conditions (as at 31 December 2023) = STI outcome

FORM OF INCENTIVE

Subject to the achievement of the performance conditions, the TY23 award is delivered to executives in two parts, a cash element (50%) and a deferred element via performance rights (50%).

The cash component is paid following the end of TY23.

The number of performance rights to be granted is to be determined by dividing 50% of the total STI award outcome by Karoon's weighted average share price in the 20-trading day period after the release of the Company's TY23 financial results.

Performance rights do not have a strike price. Each performance right provides the participant with the right to receive one fully paid ordinary share in Karoon, or its equivalent value, for no consideration where vesting conditions are met.

DEFERRAL PERIOD

Performance rights are subject to a further retention period of 12 months until December 2024, subject to continued employment.

PERFORMANCE CONDITIONS

As part of the TY23 remuneration review, the Board set out the TY23 award based on a mix of the following performance hurdles:

	COMPANY-WIDE OBJECTIVES	ROLE-SPECIFIC OBJECTIVES
CEO/MD	100%	–
Other KMP	80%	20%

Company-wide Objectives

Company-wide Objectives were set by the Board at the beginning of the performance period.

The Company-wide Objectives, known as the 'Corporate Scorecard', includes financial and operational objectives, project objectives and strategic targets.

Role-specific Objectives

Role-specific Objectives were set at the beginning of the performance period and related directly to individual/team specific responsibilities.

All short term performance outcomes are tempered by both a gateway for safety outcomes and a clawback (negative discretion) provision in relation to any fatality and bribery and/or corruption issues. Where there is a fatality during the reporting period, no STI is payable.

Further details on the performance conditions, targets and outcomes for the TY23 award are outlined below in the STI outcomes within section 6.

HOW DO STI'S RELATE TO KAROON'S OBJECTIVES

The STI framework is based on a set of challenging Company building goals, granted on a rolling short term basis. Linking outcomes to operational performance develops an essential alignment between Karoon's year-to-year inherent value growth and rewards those who establish that value only when the company objectives are met.

The Board assesses the objectives for the performance period in light of the long term strategic building blocks and upcoming key value drivers within Karoon's operations, allowing for transparent measurement of company performance against these objectives.

The Board recognises the risks associated with offshore oil production and drilling and considers ensuring the safety of the workforce and avoiding any instances of bribery and corruption as paramount to its operations. Achieving appropriate safety standards is used as a gateway for any vesting of the STI, while any fatality or instance of bribery and corruption can be utilised to claw back incentives should they have been previously paid.

CESSATION OF EMPLOYMENT

Unvested performance rights will lapse on cessation of employment with Karoon, subject to the nature and circumstances of the termination and the discretion of the Board of Directors.

CHANGE OF CONTROL

On a change of control, the Board of Directors may determine that a portion of the individual's unvested performance rights will vest based on pro-rata achievement of the performance conditions. Adjustments to an individual's unvested performance rights may also occur in the event of a Company reconstruction and certain share issuances.

DIVIDEND AND VOTING RIGHTS

Performance rights carry no dividend or voting rights during the one year deferral period.

LTI Plan

WHO PARTICIPATES

Executives. Participation in the LTI Plan is at the discretion of the Board of Directors on the recommendation of the People and Culture Committee.

LTI OPPORTUNITY

The LTI opportunity available to an executive is determined as a percentage of the executive's fixed remuneration. In respect of the TY23 LTI grant, opportunity levels have been pro-rated to reflect that TY23 had six months in the year instead of the usual 12 month period. The CEO/MD can earn up to 50% of fixed remuneration (usual annual opportunity is 100% of fixed remuneration). The CFO and EVP Brazil can earn up to 37.5% of fixed remuneration (usual annual opportunity is 75% of fixed remuneration).

The key features of the LTI grant for TY23 are outlined in the table below:

[Fixed Remuneration (at 1 July 2023) **x** 50% of annual LTI opportunity (6 month pro rata)] **x** Outcome of performance conditions (as at 30 June 2026) **=** LTI vesting outcome

FORM OF INCENTIVE

The quantum of performance rights received was determined by dividing the LTI opportunity for each executive by the volume weighted average price of Karoon Energy ordinary shares for 20 trading days from 23 August 2023 (being the date on which Karoon's 2023 full year financial results were released to the market).

Performance rights do not have a strike price. Each performance right provides the participant with the right to receive one fully paid ordinary share in Karoon, or its equivalent for no consideration.

Under the rules of the Performance Rights Plan, ordinary shares issued or provided as a result of the exercise of vested and converted performance rights may be issued as new ordinary shares or ordinary shares acquired on-market.

PERFORMANCE PERIOD

Three years (commencing 1 July 2023 and vesting on 30 June 2026).

PERFORMANCE CONDITIONS

The LTI performance hurdles are assessed against:

- 50% relative total shareholder return (TSR) against a list of closely comparable and representative industry peer group companies, whose business models and/or regions of operations are similar to those of Karoon (Industry Peer Group).
- 50% absolute TSR (based on a compound annual growth rate (CAGR)), which is set at a range of 10% to 18%.

SECTION 4. EXECUTIVE REMUNERATION FRAMEWORK FOR TY23 CONTINUED

PERFORMANCE CONDITIONS CONTINUED

Relative TSR (50%)

Relative TSR has been selected as it assesses Karoon's ability to deliver shareholder returns above that of our peers, aligning executives' incentives with the shareholder experience. Given Karoon operates internationally, the peer group comprises of a mix of domestic and global peers.

INDUSTRY PEER GROUP

AUSTRALIAN MARKET PEERS	GLOBAL PEERS
Australis Oil & Gas Limited	Capricorn Energy plc
Beach Energy Limited	GeoPark Limited
Carnarvon Energy Limited	Gran Tierra Energy Inc
Horizon Oil Limited	Kosmos Energy Ltd
Santos Limited	New Zealand Oil & Gas Ltd
Woodside Petroleum Limited	Enauta Participações S.A.
Strike Energy Limited	Pharos Energy plc
Central Petroleum Limited	Tullow Oil plc
Cooper Energy Limited	Prio S.A.
	Jadestone Energy Inc

Companies that are no longer part of the Industry Peer Group at the end of the performance period (for instance, due to acquisition or delisting) may be removed from the Peer Group calculation.

The vesting schedule for the relative TSR measure is outlined and illustrated below:

PERFORMANCE AGAINST INDUSTRY PEER GROUP	PROPORTION OF PERFORMANCE RIGHTS VESTING
Less than 50th percentile	Nil
At 50th percentile	50%
Between 50th and 75th percentile	50% plus 2% for each additional percentile ranking above the 50th percentile
At or above 75th percentile	100%

Absolute TSR (50%)

Absolute TSR has been selected as it assesses Karoon's ability to deliver positive shareholder returns at a sufficient return to shareholders over the long term. Assessed alongside relative TSR, it ensures that executives are only fully rewarded under the LTI plan where Karoon's shareholder returns exceed those of the Company's peers.

The vesting schedule for the Absolute TSR measure is outlined and illustrated below:

ABSOLUTE TSR (CAGR)	PROPORTION OF PERFORMANCE RIGHTS VESTING
Less than 10%	Nil
At 10%	50%
Between 10.01% and 17.99%	50% plus 6.25% for each additional percentile ranking above the 10% threshold
At or above 18.00%	100%

EXERCISE PERIOD	Performance rights will remain exercisable for a period of one year following vesting.
CESSATION OF EMPLOYMENT	Unvested (and unconverted) performance rights will lapse on cessation of employment with Karoon, subject to the nature and circumstances of the termination and the discretion of the Board of Directors.
CHANGE OF CONTROL	On a change of control, the Board of Directors may determine that a portion of the individual's unvested performance rights will vest, based on pro-rata achievement of the performance conditions. Adjustments to an individual's unvested performance rights may also occur in the event of a Company reconstruction and certain share issuances.
DIVIDEND AND VOTING RIGHTS	Performance rights carry no dividend or voting rights during the performance period.

SECTION 5: COMPANY PERFORMANCE OVERVIEW

Relationship between Executive Remuneration and Company Performance

Karoon has a transparent performance-based remuneration structure in place that provides a direct link between Company performance and remuneration in the short term and long term.

The tables below set out summary information about the Company's financial performance from 1 July 2019 to 31 December 2023 and how this links to the remuneration outcomes in section 6.

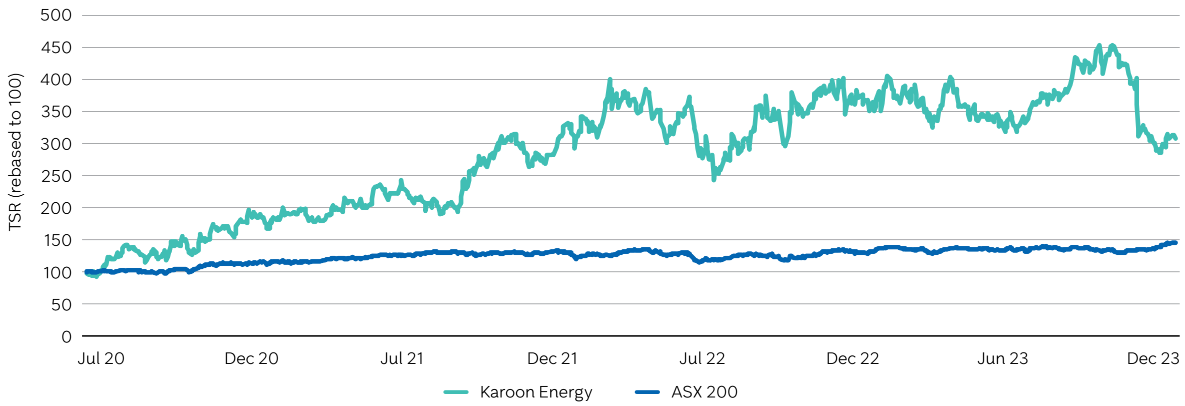
FINANCIAL PERIOD	31 DECEMBER 2023 TY23 (6 MONTHS)	30 JUNE 2023 2HFY23 (6 MONTHS)	30 JUNE 2023	30 JUNE 2022	30 JUNE 2021	30 JUNE 2020
	US$M	US$M	US$M	US$M	US$M	US$M
Revenue	**412.9**	267.1	566.5	385.1	170.8	–
Profit/(loss) before income tax	**182.1**	99.8	216.2	(89.8)	(27.9)	(86.8)
Profit/(loss) after income tax	**122.5**	85.4	163.0	(64.4)	4.4	(86.2)
Net assets at end of the period	**914.0**	473.6	473.6	276.2	380.3	359.5

FINANCIAL PERIOD	31 DECEMBER 2023 TY23 (6 MONTHS)	30 JUNE 2023 2HFY23 (6 MONTHS)	30 JUNE 2023	30 JUNE 2022	30 JUNE 2021	30 JUNE 2020
Share price at beginning of the period	**A$1.97**	A$2.19	A$1.74	A$1.33	A$0.61	A$0.96
Share price at end of the period	**A$2.03**	A$1.97	A$1.97	A$1.74	A$1.33	A$0.61
Basic earnings per ordinary share (US$)	**0.2018**	0.1517	0.2899	(0.1159)	0.0079	(0.1936)
Diluted earnings per ordinary share (US$)	**0.2003**	0.1495	0.2859	(0.1159)	0.0077	(0.1936)

No dividends were paid in the past five financial years.

Karoon Energy's TSR performance over the period 1 July 2020 to 31 December 2023 is shown below. Karoon has significantly outperformed the ASX 200 index,, delivering a return of over 200% compared to the ASX 200's return of 47% (noting that Karoon assesses its LTI's relative TSR measure against a different, industry-specific peer group).

TSR – 1 JULY 2020 TO 31 DECEMBER 2023



Source: All data has been sourced from the London Stock Exchange Group (LSEG) Data and Analytics Tool and S&P Global.

SECTION 6: EXECUTIVE REMUNERATION OUTCOMES

Performance Outcomes for TY23

The table below outlines the Company-wide Objectives, known as the Corporate Scorecard, for TY23. The 'no fatalities' gateway was met in TY23 hence KMP were eligible to receive an STI award.

The Board assessed performance for six months based on the 12 month scorecard which was set at the start of the period, commencing 1 July 2023. In assessing performance after six months, the Board exercised discretion and awarded the full year outcome for some of the project and strategic objectives below to recognise management's achievement of the full year target within six months, in:

- Executing a complex international transaction to acquire an interest in the Who Dat, Dome Patrol and Abilene oil and gas fields within TY23.
- Obtaining the required legal and regulatory approvals to transition from a June to December year end.

Both were one-off occurrences which required significant skills and experience.

We will revert to a more traditional 12 month scorecard assessment in CY24.

MEASURE	FULL YEAR WEIGHTING	PERFORMANCE THRESHOLD	PERFORMANCE TARGET	PERFORMANCE STRETCH	RESULT	OUTCOME	WEIGHTED OUTCOME
FINANCIAL AND OPERATIONAL OBJECTIVES							
Safety (% improvement)	5.0%	No improvement	10% improvement	20% improvement	TRIR = 0	100.0%	2.50%
Production (mbbl)	20.0%	5.00	5.23	6.00	5.4	51.5%	5.15%
Normalise relationship with Altera & Ocyan (A&O)	10.0%		Qualitative assessment		Achieved	50.0%	2.50%
Production Costs (US$m)	10.0%	73.8	67.0	60.3	58.9	100.0%	5.00%
Capex Budget (US$m)	2.5%	14.4	13.1	11.8	4.3	100.0%	1.25%
Other controllable corporate costs (US$m)	2.5%	15.8	14.4	12.9	14.4	50.0%	0.63%
"OneKaroon" culture evident	5.0%		Qualitative assessment		On track	80.0%	2.00%
PROJECT OBJECTIVES							
Neon strategy	10.0%			Complete Neon Foundation Project Decision Gate 1 and Neon ADP	On track	100.0%	5.00%
Re-financing (US$)	3.0%			Increase funding facility to >US$300m	US$340m	100.0%	3.00%
Change in financial year	2.0%		Qualitative assessment		Completed	100.0%	2.00%
STRATEGIC OBJECTIVES							
Acquire a substantial second production asset	20.0%			Acquire asset	Completed	100.0%	20.00%
ESG: advance carbon sequestration project	10.0%			Enter at least one project	Not met	0.0%	0.00%
Total Weighting	**100.0%**			**Corporate Scorecard Outcome**			49.03%

STI Outcomes for TY23

A summary of the STI outcomes for TY23 are detailed below.

	ANNUAL MAXIMUM STI OPPORTUNITY ($)	STI AWARDED (% OF MAXIMUM)	TY23 STI CASH	TY23 STI PERFORMANCE RIGHTS	TY23 TOTAL STI
	US$	%	US$	US$	US$
Dr J Fowles	640,036	49.0	156,809[1]	156,809	313,618
Mr R Church	490,064	49.2	120,556	120,556	241,112

1. Inclusive of superannuation contributions.

Detail on the STI arrangements for Mr Antonio Guimarães can be found in section 7, given he ceased employment during TY23.

LTI outcomes for TY23

No LTI grants were due to be tested in TY23. The next LTI grant is due to be tested on 30 June 2024.

Voluntary Information: TY23 'Remuneration Received' (Non-IFRS Information)

The amounts disclosed below reflect the actual remuneration received by each executive during TY23 and have been translated into US$ from local currencies using the average exchange rate for TY23. The average rate used for A$/US$ was 0.6535 and R$/US$ was 0.2034. The amounts disclosed below include the actual value of any equity-settled and/or cash-settled award received from STI and/or LTI.

The amounts disclosed in the table below are a voluntary disclosure and not the same as the statutory remuneration expensed in relation to each executive in accordance with Australian Accounting Standards shown in the statutory table in section 10 of the Remuneration Report.

The purpose of this table is to show the value of actual remuneration received during the financial period by executives. The remuneration values disclosed below have been determined as follows:

- Fixed remuneration comprises base salary and company superannuation/pension contributions received in TY23.
- Other benefits comprise any salary sacrifice items or non-monetary benefits, such as temporary allowances, health insurance, motor vehicles, expatriate travel, certain membership and associated fringe benefits tax received in TY23.
- Cash STI comprises the cash component received in TY23.
- Deferred STI vested and exercised comprises the equity component of the FY22 STI which vested in TY23. All vested FY22 STI awards were exercised.
- LTI vested and exercised includes the value of the vested FY21 LTI received by executives in TY23. All vested FY21 LTI awards were exercised.

	FIXED REMUNERATION	TERMINATION BENEFITS	OTHER BENEFITS	CASH STI	DEFERRED STI VESTED AND EXERCISED	LTI VESTED AND EXERCISED	TOTAL REMUNERATION RECEIVED
	US$	US$	US$	US$	US$	US$	US$
Dr J Fowles	320,963	Nil	47,609	137,106	92,468	739,542	1,337,688
Mr R Church	245,032	Nil	Nil	127,694	104,912	Nil	477,638
Mr A Guimarães	280,973	48,310	38,235	141,349	74,684	Nil	583,551

SECTION 7: EXECUTIVE AGREEMENTS

Remuneration and other terms of employment for the executives are formalised in employment agreements.

Details of existing employment agreements between the Company and current executive KMP are as follows:

NAME	TERM	NOTICE PERIOD	TERMINATION PAYMENTS
Dr J Fowles	From 27 November 2020, ongoing	Six months	Not applicable
Mr R Church	From 27 September 2021, ongoing	Six months	Not applicable

Any termination benefits for executives are subject to the limits prescribed under Section 200B of the *Corporations Act 2001*.

In TY23, Mr Antonio Guimarães ceased employment with the Company on 14 November 2023. His arrangements on termination are:

- Prior year deferred STI awards will remain on foot to vest in the ordinary course.
- Unvested LTI Performance Rights will remain on foot to be tested in the ordinary course and vest to the extent the applicable performance conditions are met.
- A pro-rated TY23 STI payable in cash.
- Payments as per his statutory requirements.
- An ex-gratia payment of US$183,650[1].
- Other benefits consistent with corporate practices, primarily comprising healthcare coverage.

SECTION 8: MINIMUM SHAREHOLDING POLICY

To ensure KMP hold a meaningful level of equity in the Company:

- Executives are required to maintain a shareholding in the Company equal to 50% of their first year after-tax fixed remuneration.
- Non-Executive Directors (NEDs) are required to maintain a shareholding in the Company equal to 50% of their after-tax base fees.

This requirement is to be met within the later of three years of their initial appointment or 30 June 2024. As at the date of this report, all persons covered by the Policy are in compliance with it.

SECTION 9: DIRECTOR FEES

Fees and payments to the Chair and other NEDs reflect the demands which are placed on, and the responsibilities of the Directors of Karoon. The Company reviews Director remuneration regularly and assesses the change to the Company's activities and overall responsibilities of each Director.

NED fees are determined with an aggregate Directors' fee pool limit, which is approved by shareholders. The maximum aggregate amount, including applicable superannuation contributions, that may be paid to NEDs of the Company as remuneration for their services per annum is A$1,200,000, as approved by shareholders at the Company's 2015 Annual General Meeting. For TY23, the total fees paid to NEDs was A$540,352.

There were no increases to base Director fees in TY23 aside from an increase in the statutory superannuation contribution of 0.5% (from 10.5% to 11%) paid to Australian resident NEDs from 1 July 2023. The last change to base Director fees occurred in FY23.

Share-based Remuneration

NEDs do not receive performance-related remuneration. NEDs will continue to be encouraged to purchase ordinary shares in the Company in accordance with the Director Minimum Shareholding Policy.

1. This has been converted from Brazilian Reais to US dollars at the six month average exchange rate of US$/R$0.2034.

NED Fees

NEDs' fees for a 12 month period (excluding any additional superannuation contributions paid to Australian Directors) are outlined in the following table. The actual amounts paid have been pro-rated for TY23:

BASE FEE	
Non-Executive Chairman[1]	A$231,000
Non-Executive Directors	A$105,000
COMMITTEE FEES	
Audit, Risk and Governance Committee	
Chair	A$30,000
Member	A$21,000
People and Culture Committee	
Chair	A$25,000
Member	A$15,750
Sustainability and Operational Risk Committee	
Chair	A$25,000
Member	A$15,750

In addition to the fees above, three Directors (Mr Botten, Mr Turnbull and Mr Davey) received a one-off additional payment of A$15,000 (including superannuation) for their participation on a Due Diligence Committee associated with the Company's M&A activities during TY23.

1. Non-Executive Chairman base fee includes compensation for the appointment to relevant Committees.

SECTION 10: STATUTORY AND SHARE-BASED REPORTING

Details of the Remuneration of the Directors and Other KMP

Details of the remuneration of the Directors and other KMP of the Group for TY23 and previous financial year are set out in the following tables. For all remuneration reporting stated in US$, exchange rates of A$/US$ 0.6535 (FY23: 0.6735) and R$/US$ 0.2034 (FY23: 0.1937) have been used.

Transitional Year for the 6 Months Ended 31 December 2023

	Short term Benefits			Post-employment Benefits			Leave Benefits	Share-based Payments Expense		
NAME	CASH SALARY AND FEES US$	NON-MONETARY BENEFITS US$	CASH STI/ BONUS US$	SUPER-ANNU-ATION/ PENSION CONTRI-BUTIONS US$	SOCIAL SECURITY & INDEMNITY FUND CONTRI-BUTIONS US$	TERMI-NATION BENEFITS US$	LEAVE ENTITLE-MENTS[1] US$	PERFOR-MANCE RIGHTS US$	PERFOR-MANCE BASED REMUNER-ATION[2] %	TOTAL REMUNER-ATION[3] US$
Executive Directors										
Dr J Fowles	292,253	47,609	143,204	42,313[4]	–	–	16,627	282,642	53.3[5]	824,648
Non-Executive Directors										
Mr B Phillips	62,896	–	–	6,919	–	–	–	–	–	69,815
Ms L Rachid	42,475	–	–	–	–	–	–	–	–	42,475
Mr C Davey	58,085	–	–	6,389	–	–	–	–	–	64,474
Mr P Turnbull	63,313	–	–	6,964	–	–	–	–	–	70,277
Mr P Botten	60,005	–	–	6,601	–	–	–	–	–	66,606
Mr T Fraga	39,453	–	–	–	–	–	–	–	–	39,453
Total Directors' remuneration	618,480	47,609	143,204	69,186	–	–	16,627	282,642		1,177,748
Other KMP (Group)										
Mr R Church	236,080	–	120,556	8,952	–	–	2,520	164,501	53.5	532,609
Mr A Guimarães	228,974	38,235	115,126	10,875	41,124	231,959[6]	(28,329)	220,820[7]	39.1	858,784
Total other KMP remuneration (Group)	465,054	38,235	235,682	19,827	41,124	231,959	(25,809)	385,321		1,391,393
Total KMP remuneration (Group)	1,083,534	85,844	378,886	89,013	41,124	231,959	(9,182)	667,963		2,569,141

1. Leave benefits include annual leave and long service leave entitlements.
2. The percentage of total remuneration consisting of performance rights, based on the value of the performance rights expensed in the consolidated statement of profit or loss and other comprehensive income during TY23.
3. Amounts disclosed for the remuneration of Directors and other KMP exclude insurance premiums paid by the Company in respect of Directors' and Officers' liability insurance contracts, as the contracts do not specify premiums paid in respect of individual Directors and Officers. Information relating to insurance contracts is set out in this Director's Report.
4. Includes superannuation contribution of US$13,605 relating to TY23 cash bonus.
5. Inclusive of superannuation contribution on Cash STI.
6. Included in this amount is an accrual of an ex-gratia payment of US$183,650 which was paid on 2 February 2024.
7. Mr A Guimarães' share-based payments expense includes the accelerated vesting of performance rights for accounting purposes, which were retained upon cessation of employment with the company. Unvested LTI performance rights will remain on foot to be tested in the ordinary course and vest to the extent the applicable performance conditions are met.

Financial Year Ended 30 June 2023

NAME	Short term Benefits: CASH SALARY AND FEES US$	Short term Benefits: NON-MONETARY BENEFITS US$	Short term Benefits: CASH STI/ BONUS US$	Post-employment Benefits: SUPER-ANNUATION/ PENSION CONTRI-BUTIONS US$	Post-employment Benefits: SOCIAL SECURITY & INDEMNITY FUND CONTRI-BUTIONS US$	Leave Benefits: LEAVE ENTITLE-MENTS[1] US$	Share-based Payments Expense: PERFOR-MANCE RIGHTS US$	PERFOR-MANCE BASED REMUNER-ATION[2] %	TOTAL REMUNER-ATION[3] US$
Executive Director									
Dr J Fowles	568,173	–	141,309	53,976	–	42,387	694,983	55.7	1,500,828
Non-Executive									
Directors									
Mr B Phillips	155,578	–	–	16,336	–	–	–	–	171,914
Ms L Rachid	87,555	–	–	–	–	–	–	–	87,555
Mr C Davey	101,530	–	–	10,661	–	–	–	–	112,191
Mr P Turnbull	112,306	–	–	11,792	–	–	–	–	124,098
Mr P Botten	95,469	–	–	10,024	–	–	–	–	105,493
Mr T Fraga	69,108	–	–	–	–	–	–	–	69,108
Total Directors' remuneration	**1,189,719**	**–**	**141,309**	**102,789**	**–**	**42,387**	**694,983**		**2,171,187**
Other KMP (Group)									
Mr R Church	441,485	40,582	131,609	17,034	–	30,160	299,529	44.9	960,399
Mr A Guimarães	323,390	75,920	86,914	28,153	48,911	6,601	198,603	37.2	768,492
Total Other KMP remuneration (Group)	**764,875**	**116,502**	**218,523**	**45,187**	**48,911**	**36,761**	**498,132**		**1,728,291**
Total KMP remuneration (Group)	**1,954,594**	**116,502**	**359,832**	**147,976**	**48,911**	**79,148**	**1,193,115**		**3,900,078**

1. Leave benefits include annual leave and long service leave entitlements.
2. The percentage of total remuneration consisting of performance rights, based on the value of performance rights expensed in the consolidated statement of profit or loss and other comprehensive income during the financial year.
3. Amounts disclosed for remuneration of Directors and other KMP exclude insurance premiums paid by the Company in respect of Directors' and officers' liability insurance contracts, as the contracts do not specify premiums paid in respect of individual Directors and officers. Information relating to insurance contracts is set out in this Directors' Report.

SECTION 10: STATUTORY AND SHARE-BASED REPORTING CONTINUED

The relative percentage proportions of remuneration that are linked to performance conditions, those that are not and those that are fixed are as follows:

	NOT RELATED TO PERFORMANCE CONDITIONS		RELATED TO PERFORMANCE CONDITIONS							
	FIXED REMUNERATION		TERMINATION PAYMENTS		CASH BONUS		STI (PERFORMANCE RIGHTS)		LTI (PERFORMANCE RIGHTS)	
NAME	TY23	FY23	TY23	FY23	TY23	FY23	TY23	FY23	TY23	FY23
Executive Director										
Dr J Fowles	**46.7%**	44.3%	**–**	–	**19.1%**	9.4%	**8.9%**	4.7%	**25.3%**	41.6%
Non-Executive Directors										
Mr B Phillips	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Ms L Rachid	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Mr C Davey	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Mr P Turnbull	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Mr P Botten	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Mr T Fraga	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Other KMP (Group)										
Mr R Church	**46.5%**	55.1%	**–**	–	**22.6%**	13.7%	**11.2%**	6.8%	**19.7%**	24.4%
Mr A Guimarães	**33.9%**	62.8%	**27.0%**	–	**13.4%**	11.3%	**5.6%**	5.6%	**20.1%**	20.3%

Further information on performance rights is set out in Note 26 of the consolidated financial statements.

Share-based Remuneration

The terms and conditions of each grant of performance rights over unissued ordinary shares in the Company affecting remuneration in the current or a future financial year are as follows:

GRANT DATE	DATE VESTED AND EXERCISABLE	EXPIRY DATE	EXERCISE PRICE PER PERFORMANCE RIGHT	FAIR VALUE PER PERFORMANCE RIGHT AT GRANT DATE	% VESTED	PERFORMANCE CONDITION ACHIEVED
Performance rights						
23 March 2022	1 July 2024	30 June 2025	$–	A$1.815	–	To be determined
6 May 2022	1 July 2024	30 June 2025	$–	A$1.525	–	To be determined
24 November 2022	1 July 2025	30 June 2026	$–	A$1.707	–	To be determined
16 December 2022	1 July 2025	30 June 2026	$–	A$1.559	–	To be determined
31 March 2023	1 July 2025	30 June 2026	$–	A$1.508	–	To be determined
14 November 2023	1 July 2024	30 June 2025	$–	A$2.400	–	To be determined
23 November 2023	1 July 2024	30 June 2025	$–	A$2.120	–	To be determined
23 November 2023[1]	1 July 2025	30 June 2026	$–	A$1.509	–	To be determined
23 November 2023	1 July 2026	30 June 2027	$–	A$1.321	–	To be determined

Number of Performance Rights provided as Remuneration during TY23

Details of performance rights over unissued ordinary shares in the Company provided as remuneration to each Director and each of the other KMP, including their personally related parties, are set out below:

NAME	NUMBER OF PERFORMANCE RIGHTS GRANTED DURING TRANSITIONAL PERIOD	FAIR VALUE PER PERFORMANCE RIGHT AT GRANT DATE	VALUE OF PERFORMANCE RIGHTS AT GRANT DATE	NUMBER OF PERFORMANCE RIGHTS VESTED DURING TRANSITIONAL PERIOD	NUMBER OF PERFORMANCE RIGHTS FORFEITED	VALUE OF PERFORMANCE RIGHTS FORFEITED
Executive Director						
Dr J Fowles						
– Performance rights (LTI)	198,809	A$1.321	A$262,627	–	–	–
– Performance rights (LTI)	12,649	A$1.509	A$19,087	–	–	–
– Performance rights (STI)	85,176	A$2.120	A$180,573	–	–	–
Other KMP (Group)						
Mr R Church						
– Performance rights (LTI)	114,169	A$1.321	A$150,817	–	–	–
– Performance rights (STI)	79,329	A$2.120	A$168,177	–	–	–
Mr A Guimarães						
– Performance rights (LTI)	–	–	–	–	–	–
– Performance rights (STI)	57,263	A$2.40	A$137,431	–	–	–
Total KMP – Performance rights	**547,395**		**A$918,712**	**–**	**–**	**–**

Long term performance rights granted during FY23 and TY23 which are subject to market-based performance conditions, have been valued using a Monte Carlo simulation approach. The fair value of the STI performance rights was based on the Company's closing share price at grant date.

1. Performance rights associated with the FY23 LTI, disclosed in the prior year remuneration report, that were approved at the 2023 Annual General Meeting

SECTION 10: STATUTORY AND SHARE-BASED REPORTING CONTINUED

Shares issued on the Conversion of Performance Rights Provided as Remuneration

Details of fully paid ordinary shares in the Company issued, as a result of the exercise and conversion of remuneration performance rights to each Director and other KMP, during the financial period, including their personally related parties, are set out below:

NAME	GRANT DATE	DATE OF CONVERSION OF PERFORMANCE RIGHTS	NUMBER OF ORDINARY SHARES ISSUED	VALUE AT CONVERSION DATE US$[1]	AMOUNT PAID PER PERFORMANCE RIGHT
Executive Directors					
Dr J Fowles					
– Performance rights (LTI)	27 November 2020	26 July 2023	502,989	739,542	$–
– Performance rights (STI)	24 November 2022	26 July 2023	62,891	92,468	$–
			565,880	**832,010**	**$–**
Other KMP (Group)					
Mr R Church					
– Performance rights (STI)	16 December 2022	20 November 2023	75,730	104,912	$–
Mr A Guimarães					
– Performance rights (STI)	16 December 2022	9 August 2023	51,251	74,684	$–
			126,981	179,596	$–
			692,861	**1,011,606**	**$–**

1. The value at conversion date of performance rights that were granted as part of their remuneration and were converted during the financial period has determined as the intrinsic value of the performance rights at that date.

Details of Remuneration – Performance Rights

For each grant of performance rights in the current or previous financial years which resulted in a share-based payment expense to Directors and other KMP, the percentage of the grant that vested and percentage that was forfeited because the individual did not meet the service and/or pre-determined performance conditions is set out below:

NAME	FINANCIAL PERIOD GRANTED	VESTED %	FORFEITED %	FINANCIAL PERIOD IN WHICH SHARE OPTIONS OR PERFORMANCE RIGHTS MAY VEST	MAXIMUM TOTAL VALUE OF GRANT YET TO VEST[1] US$
Executive Director					
Dr J Fowles					
– Performance rights (LTI)	30 June 2022	–	–	31 December 2024	95,573
– Performance rights (LTI)	30 June 2023	–	–	31 December 2025	241,083
– Performance rights (LTI)	31 December 2023	–	–	31 December 2025	6,230
– Performance rights (LTI)	31 December 2023	–	–	31 December 2026	142,887
– Performance rights (STI)	31 December 2023	–	–	31 December 2024	29,540
Other KMP (Group)					
Mr R Church					
– Performance rights (LTI)	30 June 2022	–	–	31 December 2025	45,776
– Performance rights (LTI)	30 June 2023	–	–	31 December 2025	124,990
– Performance rights (LTI)	31 December 2023	–	–	31 December 2026	82,055
– Performance rights (STI)	31 December 2023	–	–	31 December 2024	27,512
Mr A Guimarães[2]					
– Performance rights (LTI)	30 June 2022	–	–	30 June 2025	–
– Performance rights (LTI)	30 June 2023	–	–	30 June 2026	–
– Performance rights (STI)	31 December 2023	–	–	30 June 2025	–

1. The maximum value of performance rights yet to vest was determined as the amount of the grant date fair value of the performance rights that is yet to be expensed in the consolidated statement of profit or loss and other comprehensive income. The minimum value of the grant where performance/vesting conditions are not met.
2. Mr A Guimarães ceased employment with the Company on 14 November 2023. Upon termination, his unvested LTI performance rights will remain on foot to be tested in the ordinary course and vest to the extent the applicable performance conditions are met.

SECTION 10: STATUTORY AND SHARE-BASED REPORTING CONTINUED

Movement of Performance Rights over Unissued Ordinary Shares in the Company during TY23

During TY23 performance rights over unissued ordinary shares in the Company were issued to Directors and other KMP, including their personally related parties.

The movement of performance rights over unissued ordinary shares in the Company held by Directors and other KMP, including their personally related parties, during the period was as follows:

	BALANCE AS AT 1 JULY 2023	GRANTED AS REMUNER-ATION	VESTED AND EXERCISED PERFORM-ANCE RIGHTS	PERFORM-ANCE RIGHTS FORFEITED	OTHER	BALANCE AS AT 31 DECEMBER 2023	TOTAL VESTED AND EXERCIS-ABLE AS AT 31 DECEMBER 2023	TOTAL UNVESTED AS AT 31 DECEMBER 2023
Executive Director								
Dr J Fowles	1,575,509	296,634	(565,880)	–	–	1,306,263	–	1,306,263
Non-Executive Directors								
Mr B Phillips	–	–	–	–	–	–	–	–
Ms L Rachid	–	–	–	–	–	–	–	–
Mr C Davey	–	–	–	–	–	–	–	–
Mr P Turnbull	–	–	–	–	–	–	–	–
Mr P Botten	–	–	–	–	–	–	–	–
Mr T Fraga	–	–	–	–	–	–	–	–
Other KMP								
Mr R Church	598,216	193,498	(75,730)	–	–	715,984	–	715,984
Mr A Guimarães	383,419	57,263	(51,251)	–	–	389,431	–	389,431
Total KMP – Performance rights	**2,557,144**	**547,395**	**(692,861)**	**–**	**–**	**2,411,678**	**–**	**2,411,678**

All performance rights granted during TY23 were issued under the 2022 PRP.

Movement in Ordinary Shares during TY23

The number of ordinary shares held by Directors and other KMP, including their personally related parties, as at 31 December 2023 was as follows:

	BALANCE AS AT 1 JULY 2023	RECEIVED AS REMUNER-ATION	RECEIVED FROM EXERCISED PERFORM-ANCE RIGHTS	SHARES ACQUIRED	SHARES SOLD	BALANCE AS AT 31 DECEMBER 2023
Executive Director						
Dr J Fowles	107,659	–	565,880	179,611	–	853,150
Non-Executive Directors						
Mr B Phillips	1,750,000	–	–	–	–	1,750,000[1]
Mr C Davey	147,214	–	–	39,259	–	186,473
Mr P Turnbull	173,000	–	–	10,000	–	183,000
Ms L Rachid	52,960	–	–	–	–	52,960
Mr P Botten	–	–	–	50,000	–	50,000
Mr T Fraga	–	–	–	21,100	–	21,100
Other KMP						
Mr R Church	–	–	75,730	–	–	75,730
Mr A Guimarães	–	–	51,251	–	–	51,251[2]
Total KMP	**2,230,833**	–	**692,861**	**299,970**	–	**3,223,664**

1. Mr B Phillips' shareholding refers to his balance as at 23 November 2023, when he retired as Chairman.
2. Mr A Guimarães' shareholding refers to his balance as at 14 November 2023 when he ceased in his role as KMP.

None of the ordinary shares are held nominally by any Director or any of the other KMP. 'Held nominally' refers to the situation where the ordinary shares are in the name of the Director or other KMP, but they are not the beneficial owner.

Other Transactions with Directors and Other KMP

A formal Related Party Protocol requires the approval by the People and Culture Committee and, thereafter, the Board of Directors of all new related party transactions.

During TY23, the Group paid US$132,213 to Radix Engenharia e Software (Radix), an entity of which Mr Tadeu Fraga, a Non-Executive Director, is a Board member. Radix provided engineering consulting services to the Group at market prices. Mr Fraga's interest in Radix commenced on 1 March 2023, post the execution of the contract.

During TY23, Ms Fraga, a family member of Mr Tadeu Fraga, a Non-Executive Director, remained employed by the Group as P&C Co-ordinator in Brazil. The total value of her remuneration (including share-based payments expense) for TY23 was US$67,232. Ms Fraga's employment with the Karoon Group commenced prior to the appointment Mr Fraga.

Loans to Directors and Other KMP

There were no loans to Directors or other KMP during TY23.

Rounding

The amounts in the financial report are rounded to the nearest hundred thousand dollars unless otherwise indicated, under the option available to the Company under ASIC Corporations (Rounding in Financial/Directors Reports) Instrument 2016/191. The Company is an entity to which this legislative instrument applies.

This Directors' Report, incorporating the Remuneration Report, is made in accordance with a resolution of the Directors. On behalf of the Directors:

Mr Peter Botten
Independent Non-Executive Chairman

29 February 2024

Auditor's Independence Declaration

As lead auditor for the audit of Karoon Energy Ltd for the period 1 July 2023 to 31 December 2023, I declare that to the best of my knowledge and belief, there have been:

(a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and

(b) no contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Karoon Energy Ltd and the entities it controlled during the period.

Graeme McKenna
Partner
PricewaterhouseCoopers

Melbourne
29 February 2024

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CONSOLIDATED FINANCIAL STATEMENTS

FOR THE FINANCIAL PERIOD ENDED 31 DECEMBER 2023

Karoon Energy Ltd (the 'Company') is a public company limited by shares and is listed on the ASX. It is incorporated and domiciled in Australia.

The registered office and principal place of business of Karoon Energy Ltd is Suite 3.02, Level 3, 6 Riverside Quay, Southbank VIC 3006.

The consolidated financial statements are for the consolidated entity consisting of the Company and its subsidiaries.

The consolidated financial statements are presented in United States dollars.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

For the Financial Period Ended 31 December 2023

	NOTE	6 MONTHS ENDED 31 DECEMBER 2023[1] US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Revenue	3(a)	**412.9**	566.5
Cost of sales	4(a)	**(164.5)**	(283.2)
Gross profit		**248.4**	283.3
Other income	3(b)	**2.6**	5.7
Finance costs	4(b)	**(15.9)**	(25.4)
Net foreign currency gains/(losses)		**(8.1)**	(0.8)
Other expenses	4(c)	**(41.4)**	(41.4)
Change in fair value of contingent consideration	19(ii)	**(3.5)**	(5.2)
Profit/(loss) before income tax		**182.1**	216.2
Income tax expense	5(a)	**(59.6)**	(53.2)
Profit/(loss) for financial period attributable to equity holders of the Company		**122.5**	163.0
Other comprehensive income, net of income tax:			
Items that may be reclassified subsequently to profit or loss			
Exchange differences arising from the translation of financial statements into presentation currency		**11.4**	(1.5)
Net change in fair value of cash flow hedges and cost of hedging	20	**1.9**	33.3
Other comprehensive income/(loss) for financial period, net of income tax		**13.3**	31.8
Total comprehensive income/(loss) for financial period attributable to equity holders of the Company, net of income tax		**135.8**	194.8
Profit/(loss) per share attributable to equity holders of the Company:			
Basic profit/(loss) per ordinary share (cents per share)	6	**20.18**	28.99
Diluted profit/(loss) per ordinary share (cents per share)	6	**20.03**	28.59

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

1. Refer to Note 1 for change in Karoon's financial year end.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at 31 December 2023

	NOTE	AS AT 31 DECEMBER 2023[1] US$M	AS AT 30 JUNE 2023 US$M
Current assets			
Cash and cash equivalents	8	**170.4**	74.8
Receivables	9	**56.4**	73.1
Inventories	10	**18.7**	8.7
Other financial assets	19	**0.2**	3.0
Other assets		**6.6**	7.6
Total current assets		**252.3**	167.2
Non-current assets			
Oil and gas assets	12	**1,391.0**	798.7
Exploration and evaluation assets	13	**175.3**	85.7
Property, plant and equipment	14	**3.1**	2.7
Intangible assets		**0.3**	0.1
Deferred tax assets	5	**95.2**	124.7
Inventories	10	**10.8**	8.3
Other assets		**4.5**	3.0
Total non-current assets		**1,680.2**	1,023.2
Total assets		**1,932.5**	1,190.4
Current liabilities			
Trade and other payables	11	**68.3**	57.2
Borrowings	18	**0.1**	–
Current tax liabilities		**16.8**	5.6
Other financial liabilities	19	**86.0**	86.0
Lease liabilities	15	**48.7**	47.2
Provisions	16	**0.2**	0.2
Total current liabilities		**220.1**	196.2
Non-current liabilities			
Trade and other payables	11	**7.2**	5.8
Borrowings	18	**264.4**	28.1
Other financial liabilities	19	**136.5**	133.0
Lease liabilities	15	**175.7**	200.4
Provisions	16	**214.6**	153.3
Total non-current liabilities		**798.4**	520.6
Total liabilities		**1,018.5**	716.8
Net assets		**914.0**	473.6
Equity			
Contributed equity	20	**1,210.8**	907.5
Accumulated losses		**(193.3)**	(315.8)
Reserves		**(103.5)**	(118.1)
Total equity		**914.0**	473.6

The above consolidated statement of financial position should be read in conjunction with the accompanying notes.

1. Refer to Note 1 for change in Karoon's financial year end.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the Financial Period Ended 31 December 2023

	NOTE	CONTRIBUTED EQUITY US$M	ACCUMULATED LOSSES US$M	SHARE-BASED PAYMENTS RESERVE US$M	FOREIGN CURRENCY TRANSLATION RESERVE US$M	HEDGING RESERVES US$M	TOTAL EQUITY US$M
Balance as at 1 July 2022		907.5	(478.8)	53.8	(165.0)	(41.3)	276.2
Profit for financial year		–	163.0	–	–	–	163.0
Other comprehensive income (loss)		–	–	–	(1.5)	33.3	31.8
Total comprehensive income/(loss) for financial year		–	163.0	–	(1.5)	33.3	194.8
Transactions with owners in their capacity as owners:							
Share-based payments expense	26(c)	–	–	2.6	–	–	2.6
		–	–	2.6	–	–	2.6
Balance as at 30 June 2023		**907.5**	**(315.8)**	**56.4**	**(166.5)**	**(8.0)**	**473.6**
Profit for financial period		**–**	**122.5**	**–**	**–**	**–**	**122.5**
Other comprehensive income (loss)		**–**	**–**	**–**	**11.4**	**1.9**	**13.3**
Total comprehensive income/(loss) for financial period		**–**	**122.5**	**–**	**11.4**	**1.9**	**135.8**
Transactions with owners in their capacity as owners:							
Ordinary shares issued		**312.3**	**–**	**–**	**–**	**–**	**312.3**
Transaction costs associated with issue of shares		**(9.0)**	**–**	**–**	**–**	**–**	**(9.0)**
Share-based payments expense	26(c)	**–**	**–**	**1.3**	**–**	**–**	**1.3**
		303.3	**–**	**1.3**	**–**	**–**	**304.6**
Balance as at 31 December 2023[1]		**1,210.8**	**(193.3)**	**57.7**	**(155.1)**	**(6.1)**	**914.0**

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

1. Refer to Note 1 for change in Karoon's financial year end.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the Financial Period Ended 31 December 2023

	NOTE	6 MONTHS ENDED 31 DECEMBER 2023[1] US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Cash flows from operating activities			
Receipts from customers		**443.3**	552.9
Payments to suppliers and employees		**(106.2)**	(135.2)
Payments for exploration and evaluation expenditure expensed		**(3.3)**	(4.0)
Payments for cash flow hedges		**(2.7)**	(13.4)
Interest received		**1.0**	4.2
Borrowing and other costs of finance paid		**(9.2)**	(19.8)
Income taxes paid		**(19.5)**	(78.8)
Net cash flows from (used in) operating activities	8	**303.4**	305.9
Cash flows from investing activities			
Acquisition of oil and gas assets	24	**(636.8)**	(84.5)
Acquisition of exploration and evaluation assets	24	**(83.0)**	–
Interest received on deposit		**0.1**	–
Payments for oil and gas assets		**(4.2)**	(222.5)
Purchase of plant and equipment and computer software		**(0.9)**	(2.5)
Borrowing costs paid for qualifying assets		**–**	(2.7)
Payments for exploration and evaluation expenditure capitalised		**(3.3)**	(43.1)
Payment for security deposits		**–**	(0.9)
Net cash flows from (used in) investing activities		**(728.1)**	(356.2)
Cash flows from financing activities			
Principal elements of lease payments		**(19.2)**	(34.1)
Proceeds from issue of ordinary shares		**312.3**	–
Payment of equity raising costs		**(8.8)**	–
Proceeds from borrowings		**274.0**	–
Repayment of borrowings		**(29.9)**	–
Debt facility costs		**(8.6)**	(0.1)
Net cash flows from (used in) financing activities		**519.8**	(34.2)
Net increase/(decrease) in cash and cash equivalents		**95.1**	(84.5)
Cash and cash equivalents at beginning of the period		**74.8**	157.7
Effect of exchange rate changes on the balance of cash and cash equivalents held in foreign currencies		**0.5**	1.6
Cash and cash equivalents at end of the period	8	**170.4**	74.8

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

1. Refer to Note 1 for change in Karoon's financial year end.

SECTION A: ABOUT THESE STATEMENTS

NOTE 1. GENERAL INFORMATION

The consolidated financial statements are for the consolidated entity consisting of the Company and its subsidiaries (the 'Group'). Information on the nature of the operations and principal activities of the Group is described in the Directors' Report.

Change in the Financial Year End

On 7 July 2023, the Company's Board resolved to change the financial year end for the Company and all its controlled entities incorporated in Australia (refer to Note 22 on Subsidiaries) from 30 June to 31 December in accordance with the requirements of section 323D(2A) of the *Corporations Act 2001* (Cth). The change in year end was made in order to:

- streamline the preparation of annual statutory financial statements with the Company's Brazilian subsidiaries' annual financial and tax year, which ends on 31 December, and
- align with relevant oil and gas industry peers.

The first annual report of the Group after this change as contained in this report covers a six month period, beginning on 1 July 2023 and ending on 31 December 2023 (current period) compared to the 12 month period reported by Karoon in prior periods from 1 July to 30 June. The audited financial information for the 12 month period ended 30 June 2023 has been presented as comparatives for the current period in accordance with the requirements of AASB 101 *'Presentation of Financial Statements'* consisting of:

i. Consolidated statement of financial position,

ii. Consolidated statement of profit or loss and other comprehensive income,

iii. Consolidated statement of changes in equity, and

iv. Consolidated statement of cash flows.

Accordingly, the Group's consolidated financial statements for the current period as presented in this report for the period 1 July 2023 to 31 December 2023 and prior period of 1 July 2022 to 30 June 2023 are not directly comparable.

(a) Basis of Preparation

These general purpose financial statements have been prepared in accordance with Australian Accounting Standards and Interpretations issued by the Australian Accounting Standards Board (the 'AASB') and the *Corporations Act 2001* (Cth). The Company is a for-profit entity for the purpose of preparing financial statements.

The financial statements have been prepared on a going concern basis. For further details please refer to the liquidity risk section in Note 21(d).

Rounding

The amounts in the financial statements are rounded to the nearest hundred thousand dollars unless otherwise indicated, under the option available to the Company under ASIC Corporations (Rounding in Financial/Directors Reports) Instrument 2016/191. The Company is an entity to which this legislative instrument applies.

Historical Cost Convention

The consolidated financial statements have been prepared on an accrual basis under the historical cost convention as modified, when relevant, by the revaluation of selected financial assets and financial liabilities for which the fair value basis of accounting has been applied.

Comparative Figures

When required by Accounting Standards, comparative figures have been adjusted to conform to changes in presentation for the current period.

Key Accounting Estimates, Assumptions and Judgements

Revenues, expenses and the carrying amounts of certain assets and liabilities are often determined based on estimates and assumptions of future events. In applying the Group's material accounting policies, the Board of Directors and management evaluate estimates and judgements based on historical knowledge and best available current information. Estimates assume a reasonable expectation of future events and are based on current trends and economic data obtained both externally and within the Group.

The areas involving a high degree of judgement or complexity, or areas where assumptions and estimates are material to the consolidated financial statements are disclosed in the relevant notes as follows:

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS	NOTE	PAGE
Revenue from contracts with customers	Note 3	67
Income tax	Note 5	69
Impairment of oil and gas assets, Estimates of reserves quantities, Determining the lease term of contracts with renewal options	Note 12	77
Capitalised exploration and evaluation expenditure	Note 13	80
Provision for restoration	Note 16	83
Fair value measurement of financial instruments	Note 19	87
Share based payments	Note 26	103

Compliance with International Financial Reporting Standards

Compliance with Australian Accounting Standards ensures that the consolidated financial statements comply with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Climate Change

In preparing the financial statements, the impact of climate change and current climate-related legislation has been considered.

The impact of climate change is considered as the material judgement in a number of areas in the financial statements such as:

- Impairment of oil and gas assets (refer Note 12); and
- Provision for restoration (refer Note 16).

The Group continues to monitor climate related policy and its impact on the financial statements.

New, Revised or Amended Australian Accounting Standards and Interpretations that are First Effective in the Current Reporting Period

The Group has adopted all of the new, revised and/or amended Australian Accounting Standards and Interpretations issued by the AASB that are relevant to its operations and effective for the financial period ended 31 December.

New and revised Australian Accounting Standards and amendments thereof and Interpretations effective for the financial period include:

- *AASB 2021-2 Amendments to Australian Accounting Standards – Disclosure of Accounting Policies and Definition of Accounting Estimates,*
- *AASB 2021-5 Amendments to Australian Accounting Standards – Deferred Tax related to Assets and Liabilities arising from a Single Transaction,*
- *AASB 2023-2 Amendments to Australian Accounting Standards – International Tax Reform – Pillar Two Model Rules.*

The initial adoption of all of these new, revised and/or amended Australian Accounting Standards and Interpretations has not resulted in any changes to the Group's accounting policies and has had no effect on either the amounts reported for the current or previous years.

NOTE 1. GENERAL INFORMATION CONTINUED

New standards and interpretations not yet adopted

The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective. The Group is currently assessing the impact but no material impact is currently expected.

New standards and interpretations effective for the period commencing from 1 January 2024 include:

- *AASB 2020-1 Amendments to Australian Accounting Standards – Classification of Liabilities as Current or Non-current,*
- *AASB 2022-5 Amendments to Australian Accounting Standards – Lease Liability in a Sale and Leaseback,*
- *AASB 2022-6 Amendments to Australian Accounting Standards – Non-current Liabilities with Covenants,*
- *AASB 2023-1 Amendments to Australian Accounting Standards – Supplier Finance Arrangements.*

New Sustainability Standards issued by ISSB in June 2023

The International Sustainability Standards Board (ISSB) issued its inaugural sustainability disclosure standards (IFRS S1 General Requirements for Disclosure of Sustainability – related Financials Information 'IFRS S1' & IFRS S2 Climate related Disclosures 'IFRS S2') on 26 June 2023 which forms a comprehensive global baseline of sustainability disclosures designed to meet the information needs of capital market stakeholders.

IFRS S1 provides a set of disclosure requirements designed to enable companies to communicate to investors about the sustainability-related risks and opportunities they face over the short, medium and long term. IFRS S2 sets out specific climate-related disclosures and is designed to be used with IFRS S1.

The AASB has issued the exposure draft for the ASRS Standards (ED SR1 Australian Sustainability Reporting Standards – Disclosure of Climate – related Financial Information). The current intent is for the standards to be available for use for the financial year commencing 1 January 2025 for Karoon.

The Group is actively following the development, issuance and applicability of the sustainability standards in Australia.

(b) Basis of Consolidation

The consolidated financial statements incorporate the assets and liabilities of all subsidiaries of the Company as at 31 December 2023 and the results of all subsidiaries for the financial period then ended.

Karoon Group's interests in subsidiaries are set out in Note 22 and the Group consolidates these subsidiaries as it exercises control over these entities and is exposed to, or has rights to, variable returns from its involvement with these entities and has the ability to affect their returns through its power to direct the activities of these entities.

All group subsidiaries have been aligned to have a financial year end of 31 December in accordance with relevant Brazilian and Peruvian tax and accounting regulations respectively.

Accounting policies of subsidiaries have been changed, where necessary, to ensure consistency with the policies applied by the Group.

(c) Foreign Currency Transactions and Balances

Functional and Presentation Currency

Items included in the financial statements of each of the Group's subsidiaries are measured using the currency of the primary economic environment in which the subsidiary or branch operates (the 'functional currency').

The functional currency of the Company is Australian dollars. The Group's Brazilian, Peruvian and USA subsidiaries have a functional currency of US$.

The presentation currency of the consolidated financial statements is US$.

Transactions and Balances

Foreign currency transactions and year end balances are translated into the functional currency using the foreign exchange rates prevailing at the dates of the transactions and at year end exchange rates in accordance with AASB 121 *'The Effects of Changes in Foreign Exchange Rates'*, respectively, and the difference is recognised in the consolidated statement of profit or loss and other comprehensive income as Net foreign currency gains/(losses), except when they are attributable to part of the net investment in a foreign operation.

Group Companies

The results and financial position of entities within the Group that have a functional currency different from the presentation currency are translated into the presentation currency in accordance with AASB 121 *'The Effects of Changes in Foreign Exchange Rates'*, and all resulting foreign exchange differences are recognised in other comprehensive income.

On consolidation, foreign exchange differences arising on translation of foreign currency financial statements are transferred directly to the foreign currency translation reserve in the consolidated statement of financial position. The relevant differences are recognised in the consolidated statement of profit or loss and other comprehensive income during the financial period when the investment in the entity is disposed.

SECTION B: GROUP PERFORMANCE

NOTE 2. SEGMENT INFORMATION

(a) Description of Segments

The Group has identified its operating segments based on the internal reports that are reviewed and used by the Group's Executive Management Team (identified as the 'chief operating decision maker') in assessing performance and in determining the allocation of resources.

The operating segments are based on the Group's geographical location of its operations.

The Group has identified operating segments based on the following three geographic locations:

- Australia – in which the Group's head office resides and continues to assess opportunities involved in the exploration and evaluation of hydrocarbons;
- Brazil – in which the Group is currently involved in the exploration, development and production of hydrocarbons; and
- USA – On 21 December 2023, Karoon reached financial close on its acquisition of LLOG interests in the Mississippi Canyon Blocks in the Gulf of Mexico (GoM) (effective date 1 October 2023) for a consideration of US$720m. Refer to Note 24 for further detail on the asset acquisition.

'All other segments' include amounts of a corporate nature not specifically attributable to an operating segment. The comparative period included costs associated with the closure of the Group's Peruvian Branches.

The accounting policies of the reportable operating segments are the same as the Group's accounting policies.

Segment revenues and results do not include transfers between segments as intercompany balances are eliminated on consolidation.

Segment revenue is derived from an external customer who markets to a range of end customers.

The amounts provided to the chief operating decision maker with respect to total assets and total liabilities are measured in a manner consistent with that of the consolidated financial statements. Reportable segment assets and segment liabilities are equal to consolidated total assets and total liabilities respectively. These assets and liabilities are allocated in accordance with the operations of the segment.

(b) Operating Segments

SEGMENT PERFORMANCE	AUSTRALIA US$M	BRAZIL US$M	USA US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Result for financial period ended 31 December 2023					
Revenue	–	409.1	3.8	–	412.9
Other income	0.8	1.7	0.1	–	2.6
Total segment revenue	0.8	410.8	3.9	–	415.5
Expenses					
Cost of sales	–	(162.0)	(2.5)	–	(164.5)
Depreciation and amortisation expense					
– non-oil and gas assets	(0.2)	(0.3)	–	–	(0.5)
Finance costs	(1.1)	(14.6)	(0.2)	–	(15.9)
Realised losses on cash flow hedges	–	(8.5)	–	–	(8.5)
Corporate expenses	(6.8)	(7.0)	–	(0.2)	(14.0)
Net foreign currency gains/(losses)	(8.6)	0.5	–	–	(8.1)
Change in fair value of contingent consideration	–	(3.5)	–	–	(3.5)
Other	(12.1)	(6.3)	–	–	(18.4)
Profit/(loss) before income tax	(28.0)	209.1	1.2	(0.2)	182.1
Income tax (expense)/benefit	4.8	(64.2)	(0.1)	(0.1)	(59.6)
Profit/(loss) for financial period	(23.2)	144.9	1.1	(0.3)	122.5

NOTE 2. SEGMENT INFORMATION CONTINUED

SEGMENT PERFORMANCE	AUSTRALIA US$M	BRAZIL US$M	USA US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Result for financial period ended 30 June 2023					
Revenue	–	566.5	–	–	566.5
Other income	0.4	5.3	–	–	5.7
Total segment revenue	0.4	571.8	–	–	572.2
Expenses					
Cost of sales	–	(283.2)	–	–	(283.2)
Depreciation and amortisation expense					
– non-oil and gas assets	(0.3)	(0.6)	–	–	(0.9)
Finance costs	–	(25.4)	–	–	(25.4)
Realised losses on cash flow hedges	–	(7.1)	–	–	(7.1)
Corporate expenses	(12.4)	(8.2)	–	(0.1)	(20.8)
Net foreign currency gains/(losses)	1.4	(2.2)	–	–	(0.8)
Change in fair value of contingent consideration	–	(5.2)	–	–	(5.2)
Other	(3.8)	(8.9)	–	–	(12.7)
Profit/(loss) before income tax	(14.7)	231.0	–	(0.1)	216.2
Income tax (expense)/benefit	3.3	(56.5)	–	–	(53.2)
Profit/(loss) for financial period	(11.4)	174.5	–	(0.1)	163.0

FINANCIAL PERIOD ENDED 31 DECEMBER 2023	AUSTRALIA US$M	BRAZIL US$M	USA US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Total segment assets	**38.2**	**1,105.0**	**789.3**	**–**	**1,932.5**
Total segment liabilities	**277.9**	**672.3**	**68.3**	**–**	**1,018.5**

FINANCIAL PERIOD ENDED 30 JUNE 2023	AUSTRALIA US$M	BRAZIL US$M	USA US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Total segment assets	29.3	1,161.1	–	–	1,190.4
Total segment liabilities	1.1	715.7	–	–	716.8

All revenues arising from Brazil and USA arose from sales to the Group's largest customer. No other single customers contributed 10 per cent or more to the Group's revenue in either the current period or in the period ended on 30 June 2023.

(c) Other Segment Information

Additions to non-current assets, other than financial assets (refer to Note 21), during the reporting periods were:

FINANCIAL PERIOD ENDED 31 DECEMBER 2023	AUSTRALIA US$M	BRAZIL US$M	USA US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Property, plant and equipment^	**0.1**	**0.8**	**–**	**–**	**0.9**
Exploration and evaluation assets	**0.3**	**2.9**	**86.4**	**–**	**89.6**
Oil and gas assets^	**–**	**0.6**	**639.6**	**–**	**640.2**

^ Includes right-of-use assets.

FINANCIAL PERIOD ENDED 30 JUNE 2023	AUSTRALIA US$M	BRAZIL US$M	USA US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Property, plant and equipment^	0.2	2.5	–	–	2.7
Exploration and evaluation assets	–	44.8	–	–	44.8
Oil and gas assets^	–	190.9	–	–	190.9

^ Includes right-of-use assets.

NOTE 3. REVENUE AND OTHER INCOME

Karoon recognises revenue from the sale of hydrocarbons under contracts with customers at a point in time when the performance obligations are considered met, which is when control of the products or services provided are transferred to the customer. Revenue is recognised at an amount that reflects the consideration the Group expects to be entitled to, net of goods and services tax or similar taxes.

Where part or all of the transaction price is variable, revenue is recognised only to the extent that it is highly probable that a significant reversal of revenue will not occur.

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Revenue from contracts with customers

The transaction price may not be finalised at the date control passes to the customer. In such cases, a provisional transaction price is determined with reference to quoted commodity prices.

The Group estimates variable consideration based on available information from contract negotiations and market indicators.

Interest Income

Interest income on financial assets at amortised cost is recognised in other income using the effective interest method in accordance with requirements of AASB 9 *'Financial Instruments'*.

(a) Revenue

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Crude oil sales	**412.5**	566.5
Gas sales	**0.4**	–
Total revenue from contracts with customers	**412.9**	566.5

NOTE 3. REVENUE AND OTHER INCOME CONTINUED

(b) Other Income

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Interest income	**2.5**	4.0
Write-back of inventory impaired	–	1.6
Sundry income	**0.1**	0.1
Total other income	**2.6**	5.7

NOTE 4. EXPENSES

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
(a) Cost of sales		
Operating costs	**30.2**	62.0
Royalties and other government take	**45.0**	66.7
Depreciation and amortisation – oil and gas assets	**94.2**	143.0
Change in inventories	**(12.7)**	11.5
Transportation costs	**7.8**	–
Total cost of sales	**164.5**	283.2
(b) Finance costs		
Finance charges on lease liabilities	**6.8**	15.5
Discount unwinding on net present value of provision for restoration	**3.2**	5.0
Interest expense	**2.5**	2.1
Other finance costs	**3.4**	2.8
Total finance costs	**15.9**	25.4
(c) Other Expenses		
Advisory and transaction costs	**10.8**	–
Business development and other project costs	**0.7**	3.7
Exploration and evaluation expenditure expensed	**3.3**	3.9
Corporate	**14.0**	20.7
Realised losses on cash flow hedges	**8.5**	7.1
Depreciation and amortisation – non-oil and gas assets	**0.5**	0.9
Share-based payments expense	**1.4**	3.1
Social investments/sponsorships	**2.2**	1.9
Loss on disposal of non-current assets	–	0.1
Total other expenses	**41.4**	41.4

NOTE 5. INCOME TAX

Income Taxes and Other Taxes

Current tax expense, deferred tax assets and deferred tax liabilities for the Group are recognised in accordance with the requirements of AASB 112 '*Income Taxes*'.

Tax Consolidation

The Company and its wholly owned Australian subsidiaries are part of an income tax-consolidated group under Australian taxation law. The Company is the head entity in the income tax-consolidated group. Tax (expense)/benefit, deferred tax liabilities and deferred tax assets arising from temporary tax differences of the members of the income tax-consolidated group are recognised in the separate financial statements of the members of the income tax-consolidated group using the 'stand-alone taxpayer' approach, by reference to the carrying amounts in the separate financial statements of each company and the tax values applying under tax consolidation. Current tax liabilities and tax assets and deferred tax assets arising from unused tax losses and tax credits of members of the income tax-consolidated group are recognised by the Parent Company (as head entity of the income tax-consolidated group).

Due to the existence of a tax funding agreement between the companies in the income tax-consolidated group, each company contributes to the income tax payable or receivable in proportion to their contribution to the income tax-consolidated group's taxable income. Differences between the amounts of net tax assets and tax liabilities are derecognised and the net amounts recognised pursuant to the funding agreement are recognised as either a contribution by, or distribution to, the head entity.

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Income Tax

The Group is subject to income taxes in Australia, Brazil, USA and other jurisdictions where it has foreign operations. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Group estimates its tax liabilities based on the Group's understanding of the relevant tax laws. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax balances in the financial period in which such determination is made.

Assessing the future utilisation of tax losses and temporary tax differences requires the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws. To the extent that future utilisation of these tax losses and temporary tax differences becomes probable, this could result in significant changes to deferred tax assets recognised, which would in turn impact future financial results.

NOTE 5. INCOME TAX CONTINUED

The table below provides details of the income tax recognised during the period in the consolidated statement of profit or loss and other comprehensive income and directly in equity:

	NOTE	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
(a) Income Tax Recognised in the Consolidated Statement of Profit or Loss and Other Comprehensive Income			
Tax expense/(income) comprises:			
Current income tax		**26.3**	74.0
Deferred income tax		**33.3**	(20.8)
Total income tax expense/(benefit)		**59.6**	53.2
The prima facie tax on profit/(loss) before income tax is reconciled to tax expense/(benefit) as follows:			
Prima facie tax expense/(benefit) on profit before income tax, calculated at the Brazilian tax rate of 34%		**61.9**	73.5
Add/(subtract) the tax effect of:			
Share-based payments expense (non-cash)		**0.3**	0.7
Other non-deductible items		**4.4**	1.4
Other tax benefits		**(8.3)**	–
Social investments/sponsorships[(i)]		**(2.2)**	(1.1)
Difference in overseas tax rates		**0.6**	0.4
Foreign exchange differences		**2.9**	(21.7)
Total income tax expense/(benefit)		**59.6**	53.2
(b) Amounts Recognised Directly in Equity			
Aggregate current and deferred tax arising during the financial period and not recognised in net profit or loss, but directly debited or credited in equity:			
Deferred tax – debited/(credited) directly in hedging reserves	20(d)(iii)	**1.2**	(16.9)

(i) This is a scheme which under Brazilian tax law permits a company when paying tax to direct a portion of this payment to specific government approved projects. There is no net cost to the Company as this amount replaces tax payable. It is classified as an expense in the financial statements.

	BALANCE AS AT 1 JULY 2023 US$M	(CHARGED) CREDITED TO PROFIT OR LOSS US$M	(CHARGED) CREDITED DIRECTLY TO EQUITY US$M	NET FOREIGN CURRENCY DIFFERENCE ON TRANSLATION OF FINANCIAL STATEMENTS OF FOREIGN SUBSIDIARIES US$M	TAX LOSSES UTILISED US$M	BALANCE AS AT 31 DECEMBER 2023 US$M
(c) Deferred Tax Balances						
Temporary differences						
Provisions and accruals	31.0	9.9	–	–	–	**40.9**
Depreciation of oil and gas assets	–	(48.6)	–	–	–	**(48.6)**
Unrealised foreign currency (gains)/losses	(20.7)	(4.1)	–	–	–	**(24.8)**
Translation adjustment	38.8	(5.7)	–	–	–	**33.1**
Fair value movement of financial liabilities	61.4	7.1	–	–	–	**68.5**
Farm-out expenditures	0.1	–	–	–	–	**0.1**
Right-of-use assets	(79.9)	12.8	–	–	–	**(67.1)**
Lease liabilities	94.6	(6.7)	–	–	–	**87.9**
Hedge premium	(5.3)	2.1	–	–	–	**(3.2)**
Net changes of cash flow hedges	4.3	–	(1.2)	–	–	**3.1**
Other	0.4	–	–	–	–	**0.4**
Total temporary differences	124.7	(33.2)	(1.2)	–	–	**90.3**
Unused tax losses						
Tax losses	–	4.7	–	0.2	–	**4.9**
Total unused tax losses	–	4.7	–	0.2	–	**4.9**
Net deferred tax assets/ (liabilities)	124.7	(28.5)	(1.2)	0.2	–	**95.2**

NOTE 5. INCOME TAX CONTINUED

	BALANCE AS AT 1 JULY 2022 US$M	(CHARGED) CREDITED TO PROFIT OR LOSS US$M	(CHARGED) CREDITED DIRECTLY TO EQUITY US$M	NET FOREIGN CURRENCY DIFFERENCE ON TRANSLATION OF FINANCIAL STATEMENTS OF FOREIGN SUBSIDIARIES	TAX LOSSES UTILISED US$M	BALANCE AS AT 30 JUNE 2023 US$M
Temporary differences						
Provisions and accruals	19.6	11.4	–	–	–	31.0
Equity raising transaction costs	0.2	(0.1)	–	–	–	0.1
Unrealised foreign currency (gains)/losses	(12.7)	(8.0)	–	–	–	(20.7)
Translation adjustment	14.2	24.6	–	–	–	38.8
Fair value movement of financial liabilities	79.6	(18.2)	–	–	–	61.4
Farm-out expenditures	0.1	–	–	–	–	0.1
Right-of-use assets	(95.4)	15.5	–	–	–	(79.9)
Lease liabilities	98.2	(3.6)	–	–	–	94.6
Hedge premium	(4.5)	(0.8)	–	–	–	(5.3)
Net changes of cash flow hedges	21.2	–	(16.9)	–	–	4.3
Other	0.3	–	–	–	–	0.3
Total temporary differences	120.8	20.8	(16.9)	–	–	124.7
Unused tax losses						
Tax losses	2.2	–	–	–	(2.2)	–
Total unused tax losses	2.2	–	–	–	(2.2)	–
Net deferred tax assets/ (liabilities)	123.0	20.8	(16.9)	–	(2.2)	124.7

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
(d) Unrecognised Deferred Tax Assets		
A deferred tax asset has not been recognised in the consolidated statement of financial position as the benefits of which will only be realised if the conditions for deductibility occur:		
Unrecognised temporary tax differences relating to deferred tax assets at a tax rate of 34%(i)	**16.5**	16.5
Tax losses: Peruvian operating losses at a tax rate of 32%	**6.4**	6.4
Potential tax asset	**22.9**	22.9

(i) The amount for unrecognised temporary tax differences at 31 December 2023 and 30 June 2023 relates to the impairment of the Goiá exploration asset, which was fully impaired at 30 June 2018.

NOTE 6. EARNINGS PER SHARE

Basic earnings per ordinary share is calculated by dividing the profit or loss attributable to owners of the Company, excluding any costs of servicing equity other than ordinary shares, by the weighted average number of ordinary shares outstanding during the financial period, adjusted for any bonus elements in ordinary shares issued during the financial period.

Diluted Earnings Per Share

Diluted earnings per ordinary share adjusts the figures used in the determination of basic earnings per ordinary share to take into account dilutive potential ordinary shares and the weighted average number of ordinary shares that would have been outstanding assuming the conversion of all dilutive potential ordinary shares.

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Profit/(loss) for the financial period used to calculate basic and diluted earnings per ordinary share:	**122.5**	163.0
(a) Basic earnings per ordinary share (cents per share)	**20.18**	28.99
(b) Diluted earnings per ordinary share (cents per share)	**20.03**	28.59
Weighted average number of ordinary shares on issue during the financial period used in calculating basic earnings per ordinary share:	**606,743,713**	562,290,221
Weighted average number of potential ordinary shares:	**4,720,331**	7,816,439
Weighted average number of ordinary shares and potential ordinary shares used in calculating diluted earnings per ordinary share:	**611,464,044**	570,106,660

Potential ordinary shares

Performance rights over unissued ordinary shares of the Company outstanding at the end of the financial period are considered to be potential ordinary shares and have been included in the determination of diluted earnings per ordinary share to the extent to which they are dilutive. The potential ordinary shares have not been included in the determination of basic earnings per ordinary share.

NOTE 7. DIVIDENDS

There were no ordinary dividends declared or paid during the financial period by the Group (30 June 2023: $Nil).

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Balance of franking account available for subsequent reporting periods	**12.7**	14.4

The above amount is calculated from the balance of the Company's franking account as at the end of the financial period. Franking credits are based on the Australian tax rate of 30%.

SECTION C: WORKING CAPITAL

NOTE 8. CASH AND CASH EQUIVALENTS

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Cash at bank and on hand	**170.4**	74.8
Total cash and cash equivalents	**170.4**	74.8

Reconciliation of Profit/(Loss) for Financial Period to Net Cash Flows From Operating Activities

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Profit/(loss) for financial period	**122.5**	163.0
Add (subtract)		
Non-cash items included in profit/(loss) for financial period:		
Depreciation and amortisation	**94.7**	143.8
Amortisation of finance costs	**2.0**	1.1
Change in fair value of derivative financial instruments	**3.1**	50.2
Change in fair value of contingent consideration	**3.5**	5.2
Discount unwinding on provision for restoration and deferred consideration	**3.2**	5.0
Share-based payments expense	**1.3**	2.6
Net foreign currency losses (gains)	**10.3**	(3.0)
Loss on disposal of non-current assets	**–**	0.1
Write-back of inventory impaired	**–**	(1.6)
Items classified as investing/financing activities:		
Net foreign currency gains (losses)	**(0.8)**	0.6
Change in operating assets and liabilities: **(Increase)/decrease in assets**		
Receivables – current	**27.5**	(14.7)
Oil inventories	**(12.9)**	11.5
Deferred tax assets	**28.3**	(1.7)
Other financial assets – derivative financial instruments	**2.8**	(3.0)
Other assets	**(0.5)**	2.4

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Increase /(decrease) in liabilities		
Trade and other payables – current	**5.5**	15.6
Trade and other payables – non-current	**1.4**	(1.0)
Provisions – current	**–**	(0.2)
Current tax liabilities	**11.5**	(4.0)
Deferred tax liabilities	**–**	(16.9)
Other financial liabilities – derivative financial instruments	**–**	(49.1)
Net cash flows from operating activities	**303.4**	305.9

NOTE 9. RECEIVABLES

Receivables are generally non-interest-bearing amounts and normally have 30-45 days terms. They are recognised initially at the amount of the consideration that is unconditional unless they contain significant financing components, when they are recognised initially at fair value.

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Trade receivables	**40.0**	69.6
Other receivables	**16.4**	3.5
Total current receivables	**56.4**	73.1

(a) Impairment of Receivables and Financial Risk Management

Information concerning the impairment of the Group's receivables and the respective exposure to financial risks on receivables is set out in Note 21 *'Financial Risk Management'*.

NOTE 10. INVENTORIES

Inventories are measured at the lower of cost and net realisable value in accordance with the requirements of AASB 102 *'Inventories'*. Cost for petroleum products, which comprise extracted crude oil stored in the FPSO, are valued using the absorption cost method.

Other inventories are represented by assets acquired from third parties, in the form of casing and other drilling inventory to be consumed or used in exploration and evaluation activities or production activities. They are presented as current assets unless inventories are not expected to be consumed or used in exploration and evaluation activities within 12 months. The cost of casing and other drilling inventory includes direct materials, direct labour and transportation costs.

NOTE 10. INVENTORIES CONTINUED

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Current		
Petroleum inventories	**18.5**	5.8
Casing and other drilling inventory	**0.2**	2.9
Total current inventories	**18.7**	8.7
Non-current		
Casing and other drilling inventory	**10.8**	8.3
Total non-current inventories	**10.8**	8.3

NOTE 11. TRADE AND OTHER PAYABLES

Trade and other payables are initially recognised at their fair value and subsequently measured at amortised cost using the effective interest method. These amounts represent liabilities for goods and services provided to the Group prior to the end of the reporting period that are unpaid and arise when the Group becomes obliged to make future payments in respect of the purchase of goods and services. The amounts are unsecured and are usually paid within 30 days of recognition. They are presented as current liabilities unless payment is not due within 12 months from the reporting date.

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Current		
Trade payables	**55.6**	47.8
Sundry payables and accruals (refer note (b) below)	**12.7**	8.1
Cash-settled share-based payments	**–**	1.3
Total current trade and other payables	**68.3**	57.2
Non-current (unsecured)		
Sundry payables and accruals	**7.2**	5.8
Total non-current trade and other payables	**7.2**	5.8

(a) Financial Risk Management

Information concerning the Group's exposure to financial risks on payables is set out in Note 21 *'Financial Risk Management'*.

(b) Wages, Salaries, Annual Leave and Personal Leave

Liabilities for wages and salaries, including non-monetary benefits and annual leave expected to be settled within 12 months after the end of the reporting period in which the employees render the related services are recognised in respect of employees' services up to the end of the reporting period. These liabilities are recognised within Sundry payables and accruals. They are measured at the amounts expected to be paid when the liabilities are settled plus related on-costs. Expenses for non-vesting personal leave are recognised when the leave is taken and are measured at the rates paid or payable.

The obligations are presented as current liabilities in the consolidated statement of financial position if the Group does not have an unconditional right to defer settlement for at least 12 months after the reporting date, regardless of when the actual settlement is expected to occur.

Trade and other payables are unsecured and usually paid within 30 days of recognition.

SECTION D: OPERATIONAL ASSETS AND LIABILITIES

NOTE 12. OIL AND GAS ASSETS

Production assets

Production assets include the costs to acquire, construct, install or complete production and infrastructure facilities, capitalised borrowing costs, transferred exploration and evaluation assets, development wells and the estimated cost of dismantling and restoration. Subsequent capital costs, including major maintenance, are included in the asset's carrying amount only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be reliably measured.

Assets in development

When the technical and commercial feasibility of an undeveloped oil or gas field has been demonstrated and approval of commercial development occurs, the field enters its development phase. The costs of oil and gas assets in development are separately accounted for and include past exploration and evaluation costs, development drilling and other subsurface expenditure, surface plant and equipment and any associated land and buildings. When the committed development expenditure programs are completed and commercial production commences, these costs are subject to amortisation.

Amortisation of production assets

Amortisation is calculated using the units of production method for an asset or group of assets from the date of commencement of production.

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Impairment of oil and gas assets

The Group assesses whether oil and gas assets are impaired at least on a semi-annual basis. This requires review of the indicators of impairment and in the event indicators of impairment are identified, an estimation of the recoverable amount of the cash-generating unit to which the assets belong. For oil and gas properties, expected future cash flow estimation is based on reserves, future production profiles, commodity prices and costs. Current climate change legislation is also considered in relation to oil price forecasts and the cash generating unit's useful life. Future uncertainty around climate change risks continue to be monitored.

Estimates of reserves quantities used in amortisation and impairment/impairment reversal calculations

The estimated quantities of Proved plus Probable ("2P") hydrocarbon reserves reported by the Group are integral to the calculation of amortisation expense and to the assessment of impairment or impairment reversals.

Estimated reserves quantities are based on management's interpretations of geological and geophysical models, reservoir engineering and production engineering analyses and models, and assessments of the technical feasibility and commercial viability of producing the reserves, taking into consideration reviews by an independent third party. An external reserves assessment is planned to be undertaken at least every three years.

Assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes. The Group prepares its reserves estimates in accordance with the Petroleum Resources Management System (SPE-PRMS 2018) published by the Society of Petroleum Engineers and the Australian Securities Exchange Listing rules. All estimates of reserves reported by the Group are prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator.

Estimates of reserves may change from period to period as the economic assumptions used to estimate the reserves can change from period to period, and as additional geological data is generated during the course of operations. These changes may impact depreciation, amortisation, asset carrying values, restoration provisions and deferred tax balances. If proved and probable reserves estimates are revised downwards, earnings could be affected by a higher depreciation and/or amortisation charge or immediate write-down of the assets carrying value.

NOTE 12. OIL AND GAS ASSETS CONTINUED

Right-of-use assets

The right-of-use assets are initially measured at cost (present value of the lease liability plus deemed cost of acquiring the asset), and subsequently at cost less any accumulated depreciation, impairment losses and adjustment for remeasurement of the lease liability.

The FPSO vessel lease has a fixed term to February 2026 with renewal options available. Refer to Note 15 'Leases' for the lease liabilities related to Right-of-use assets held by Karoon at the end of the financial period.

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Determining the lease term of contracts with renewal options

The Group determines the lease term as the non-cancellable term of the lease, together with any periods covered by an option to extend the lease if it is reasonably certain to be exercised, or any periods covered by an option to terminate the lease, if it is reasonably certain not to be exercised.

The Group has several lease contracts that include renewal options. The Group applies judgement in evaluating whether it is reasonably certain whether or not to exercise the option to renew the lease. That is, it considers all relevant factors that create an economic incentive for it to exercise the renewal. After the commencement date, the Group reassesses the lease term if there is a significant event or change in circumstances that is within its control and affects its ability to exercise or not to exercise the option to renew or to terminate. The Group included the renewal periods as part of the lease term for the FPSO right-of-use asset as there will be a significant negative effect on production if a replacement asset is not readily available.

	NOTE	PRODUCTION ASSET US$M	DEVELOPMENT ASSET US$M	RIGHT OF USE ASSETS US$M	CONSOLIDATED TOTAL US$M
Financial period ended 30 June 2023					
Balance at beginning of financial period		404.4	46.5	282.1	733.0
Additions during the period	2(c)	63.0	127.9	–	190.9
Transfers from property, plant and equipment		12.0	–	–	12.0
Remeasurement of lease arrangements		–	–	(5.7)	(5.7)
Borrowing costs capitalised(i)		–	2.7	–	2.7
Depreciation expense		(85.5)	–	(57.5)	(143.0)
Net increase in provision for restoration(ii)	16(b)	8.8	–	–	8.8
Completions and transfers		177.1	(177.1)	–	–
Carrying amount at end of financial period		579.8	–	218.9	798.7
At 30 June 2023					
At cost		757.1	–	349.0	1,106.1
Accumulated depreciation		(177.3)	–	(130.1)	(307.4)
Carrying amount at end of financial period		579.8	–	218.9	798.7
Financial period ended 31 December 2023					
Balance at beginning of financial period		579.8	–	218.9	798.7
Acquisitions during the period	24	636.8	–	–	636.8
Additions during the period	2(c)	0.6	2.8	–	3.4
Disposals during the period		(0.8)	–	–	(0.8)
Tax credits receivable		(11.0)	–	–	(11.0)
Depreciation expense		(60.8)	–	(33.4)	(94.2)
Net increase in provision for restoration(ii)	16(b)	58.1	–	–	58.1
Carrying amount at end of financial period		1,202.7	2.8	185.5	1,391.0
At 31 December 2023					
At cost		**1,440.8**	**2.8**	**349.0**	**1,792.6**
Accumulated depreciation		**(238.1)**	**–**	**(163.5)**	**(401.6)**
Carrying amount at end of financial period		**1,202.7**	**2.8**	**185.5**	**1,391.0**

(i) The capitalised borrowing costs related to an apportionment of the fees incurred in connection with the syndicated loan facility (refer Note [18]) relating to the Patola development, which met the definition of a qualifying asset.

(ii) Includes the addition of restoration obligations relating to the acquisition of Karoon interests in the US GoM Assets, offset by an increase in the discount rate on total restoration provisions (refer Note 16). In the prior year a provision was recognised for Brazilian restoration obligations relating to the Patola wells.

NOTE 13. EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. Expenditure in respect of each area of interest is accounted for using the 'successful efforts' method of accounting. The 'successful efforts' method requires all exploration and evaluation expenditure in relation to an area of interest to be expensed in the period it is incurred, except the cost of successful wells, the costs of acquiring interests in new exploration assets, and appraisal costs relating to determining development feasibility, which are capitalised as exploration and evaluation assets.

Exploration and evaluation assets are recognised in relation to an area of interest when the rights to tenure of the area of interest are current and either:

- it is expected to be recovered through sale or successful development and exploitation of the area of interest; or
- relates to an exploratory discovery for which at balance date a reasonable assessment of the existence or otherwise of economically recoverable reserves is not yet complete, or additional appraisal work is underway or planned.

All exploration expenditure in relation to directly attributable general administration costs, geological and geophysical costs, seismic and pre-tenure costs is expensed in the consolidated statement of profit or loss and other comprehensive income as incurred.

For exploration wells, costs directly associated with drilling the wells are initially capitalised on a well-by-well basis pending the evaluation of whether potentially economic reserves of hydrocarbons have been discovered. If no recoverable hydrocarbons are identified, or discoveries are deemed non-commercial, then the capitalised costs are expensed.

As capitalised exploration and evaluation expenditure is not available for use, it is not amortised.

Cash flows associated with exploration and evaluation expenditure expensed are classified as operating activities in the consolidated statement of cash flows. Whereas cash flows associated with capitalised exploration and evaluation expenditure are classified as investing activities.

When the technical feasibility and commercial viability of extracting economically recoverable reserves have been demonstrated, any related capitalised exploration and evaluation expenditure is reclassified as development expenditure in the consolidated statement of financial position. Prior to reclassification, capitalised exploration and evaluation expenditure is assessed for impairment.

Petroleum tenement acquisition costs are capitalised, along with licence costs paid in connection with a right to explore in an existing exploration area.

Impairment of Capitalised Exploration and Evaluation Expenditure

The carrying value of capitalised exploration and evaluation expenditure is assessed for impairment at the asset level whenever facts and circumstances (as defined in AASB 6 *'Exploration for and Evaluation of Mineral Resources'*) suggest that the carrying amount of the asset may exceed its recoverable amount. If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated.

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Capitalised Exploration and Evaluation Expenditure

Capitalised exploration and evaluation expenditure is carried forward on the basis that exploration and evaluation operations in the areas of interest have not at the end of the reporting period reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and active and significant operations in, or in relation to, the areas of interest are continuing.

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the related exploration tenement itself or, if not, whether it successfully recovers the related exploration and evaluation asset through sale. Factors that could affect the future recoverability include the level of economically recoverable reserves, future technological changes which could impact the cost of development, future legal changes (including changes to environmental and restoration obligations) and changes to commodity prices. To the extent that capitalised exploration and evaluation expenditure is determined not to be recoverable in the future, the relevant capitalised amount will be impaired in the consolidated statement of profit or loss and other comprehensive income and net assets will be reduced during the financial period in which this determination is made.

Information on the reasonable existence or otherwise of economically recoverable reserves is progressively gained through geological analysis and interpretation, drilling activity and prospect evaluation during a normal exploration tenement term. A reasonable assessment of the existence or otherwise of economically recoverable reserves can generally only be made, therefore, at the conclusion of those exploration and evaluation activities.

	NOTE	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
The reconciliation of exploration and evaluation expenditure carried forward is set out below:			
Balance at beginning of financial period		**85.7**	40.9
Acquisitions during the period	24	**83.0**	–
Additions during the period	2(c)	**6.6**	44.8
Carrying amount at end of financial period		**175.3**	85.7

NOTE 14. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is stated at cost less accumulated depreciation and any accumulated impairment losses. Such cost includes the cost of replacing parts that are eligible for capitalisation when the cost of replacing the parts is incurred. Similarly, when each major inspection is performed, its cost is recognised in the carrying amount of the plant and equipment as a replacement only if it is eligible for capitalisation. All other repairs and maintenance are recognised as an expense in the consolidated statement of profit or loss and other comprehensive income as incurred.

Commencing from the time the plant and equipment is held ready for use, depreciation expense is calculated on a straight-line basis to allocate their cost amount, net of their residual values, over their estimated useful lives ranging from two to 10 years.

Plant and equipment residual values, useful lives and depreciation methods are reviewed, and adjusted if appropriate, at the end of each reporting period.

Gains and losses on disposals are determined by comparing proceeds with the net carrying amount. These gains and losses are included in the consolidated statement of profit or loss and other comprehensive income.

NOTE 14. PROPERTY, PLANT AND EQUIPMENT CONTINUED

Right-of-use assets

Property leases generally have terms between two and five years. Refer to Note 12 'Oil and Gas assets' for the accounting policy and key accounting estimates, assumptions and judgements and Note 15 'Leases' for the lease liabilities measurement related to right-of-use assets held by Karoon at the end of the financial period.

	NOTE	PLANT AND EQUIPMENT US$M	RIGHT OF USE ASSETS US$M	CONSOLIDATED TOTAL US$M
At 30 June 2023				
At cost		3.1	1.7	4.8
Accumulated depreciation		(1.4)	(0.7)	(2.1)
Carrying amount at end of financial period		1.7	1.0	2.7
Financial period ended 31 December 2023				
Balance at beginning of financial period		1.7	1.0	2.7
Additions	2(c)	0.7	0.2	0.9
Depreciation expense		(0.4)	(0.1)	(0.5)
Carrying amount at end of financial period		2.0	1.1	3.1
At 31 December 2023				
At cost		**3.8**	**1.9**	**5.7**
Accumulated depreciation		**(1.8)**	**(0.8)**	**(2.6)**
Carrying amount at end of financial period		**2.0**	**1.1**	**3.1**

NOTE 15. LEASES

The Group has lease contracts for property, an FPSO vessel and other equipment used in its operations. The Group recognises a right-of-use asset and a lease liability at the lease commencement date. The lease liability is initially recognised at the present value of the lease payments expected to be paid over the lease term, discounted using the Group's estimated incremental borrowing rate. The lease liability is subsequently increased by the interest cost on the lease liability and decreased by lease payments made and is further remeasured if the estimated future lease payments change as a result of index or rate changes, residual value guarantees or likelihood of exercise of purchase, extension or termination options.

Right-of-use assets

The Group has applied judgement to determine the lease term for lease contracts that include renewal options. The assessment of whether the Group is reasonably certain to exercise such options impacts the lease term, which affects the measurement of lease liabilities and right-of-use assets recognised.

Refer to Note 12 'Oil and Gas assets' and Note [14] 'Property, plant and equipment' for the right-of-use assets held by Karoon at the end of the financial period.

Lease liabilities

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Current	**48.7**	47.2
Non-current	**175.7**	200.4
Total lease liabilities	**224.4**	247.6
	6 MONTHS ENDED 31 DECEMBER 2023 US$M	**12 MONTHS ENDED 30 JUNE 2023 US$M**
Reconciliation		
Balance at beginning of financial period	**247.6**	288.9
Remeasurement of lease arrangements	**–**	(5.7)
Additions during the period	**0.2**	–
Adjustment to fixed lease payments	**(4.2)**	(1.6)
Accretion of interest during the period	**6.8**	15.5
Payments made during the period	**(26.1)**	(49.6)
Net foreign currency differences	**0.1**	0.1
Total lease liabilities	**224.4**	247.6

NOTE 16. PROVISIONS

Provisions are recognised by the Group in accordance with the requirements of AASB 137 *'Provisions, Contingent Liabilities and Contingent Assets'* and AASB 119 *'Employee benefits'*.

Restoration Costs

A provision for restoration is provided by the Group where there is a present obligation as a result of exploration, development or production activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation. The estimated future obligations include the estimated costs of decommissioning and removing an asset and restoring the site. These costs are capitalised within the cost of the associated assets and the provision is stated in the consolidated statement of financial position at total estimated present value. These costs are based on judgements and assumptions regarding removal dates, technologies, industry practice and relevant legislation. Over time, the liability is increased for the change in the present value based on a risk adjusted pre-tax discount rate appropriate to the risks inherent in the liability. The costs of restoration are brought to account in the consolidated statement of profit or loss and other comprehensive income through amortisation of the associated assets over the economic life of the projects with which these costs are associated. The unwinding of the discount is included as an accretion charge within finance costs.

Long Service Leave

A provision has been recognised for employee entitlements relating to long service leave measured at the discounted value of estimated future cash outflows. In determining the provision, consideration is given to employee wage increases and the probability that the employee may satisfy vesting requirements. The cash outflows are discounted using market yields with terms of maturity that match the expected timing of cash outflows.

Employee entitlements relating to long service leave are presented as a current provision in the consolidated statement of financial position if the Group does not have an unconditional right to defer settlement for at least 12 months after the reporting period, regardless of when the actual settlement is expected to occur.

NOTE 16. PROVISIONS CONTINUED

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Provision for Restoration

Restoration costs are a normal consequence of operating in the oil and gas industry. A provision has been recognised for the Group's restoration obligations for the Baúna and US GoM fields.

In determining an appropriate level of provision, consideration is given to the expected future costs to be incurred, the timing of these expected future costs, the estimated future level of inflation and appropriate discount rate. The ultimate costs of restoration are uncertain and cost estimates could be subject to revisions in subsequent years due to many factors including changes to the relevant legal and legislative requirements, the emergence of new restoration techniques or experience at other fields. Risks associated with climate change also continue to be monitored. Likewise, the appropriate future discount rates used in the calculation are subject to change according to the risks inherent in the liability. The discount rate used to determine the restoration obligation at 31 December 2023 was based on applicable government bond rates with a tenure aligned to the tenure of the liability.

Changes to any of the estimates could result in a significant change to the level of provisioning required, which would in turn impact future financial results.

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Current		
Provision for long service leave (refer note (a) below)	**0.2**	0.2
Total current provision	**0.2**	0.2
Non-current		
Provision for restoration (refer note (b) below)	**214.6**	153.3
Total non-current provisions	**214.6**	153.3

(a) Provision for Long Service Leave

A provision was recognised for employee entitlements relating to long service leave based on the measurement and recognition criteria relating to long service leave entitlements as described in the policy above.

The current portion of this provision includes all the unconditional entitlements to long service leave where employees have completed the required period of service and also those where employees are entitled to pro-rata payments in certain circumstances.

(b) Reconciliation of provision for restoration

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Balance at beginning of financial period	**153.3**	139.5
Additions (refer note (i) below) during the period	**60.1**	23.8
Discount unwinding on provision for restoration	**3.2**	5.0
Impact of increase in discount rate	**(2.0)**	(15.0)
Total provision for restoration	**214.6**	153.3

(i) During the period a provision was recognised for US restoration obligations relating to the US GoM wells based on the measurement and recognition criteria relating to restoration obligations as described in the policy above. In the prior year a provision was recognised for Brazilian restoration obligations relating to the Patola wells.

In September 2023, Karoon provided the ANP a surety bond totalling BRL$475.4 million (US$98.2 million equivalent as at 31 December 2023) in respect of existing decommissioning obligations relating to the Baúna field. A Parent Company guarantee totalling BRL$117.7 million (US$24.3 million equivalent as at 31 December 2023) was provided previously. The surety bond will top up and replace the Parent Company guarantee once formally approved by the ANP. Management expects this formal acceptance of the surety bond in the first half of 2024.

NOTE 17. CONTINGENT LIABILITIES AND CONTINGENT ASSETS

(a) Contingent Liabilities

The Group has contingent liabilities as at 31 December 2023 that may become payable in respect of:

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
(i) The Group has provided the ANP a letter of credit to carry out the minimum work program in relation to exploration in Santos Basin Block S-M-1537. The Directors are of the opinion that the work program commitments will be satisfied. The letter of credit is fully funded by way of payment of a security deposit, which will be released once the work program is met.	**2.1**	2.1
(ii) Bank guarantees were provided in respect of rental agreements for office premises of the Group. These guarantees may give rise to liabilities for the Group if obligations are not met under these guarantees. The bank guarantees given to lessors are fully funded by way of payment of security deposits.	**0.2**	0.2
(iii) Cash deposits are held as bonds for the Group's compliance with its obligations in respect of agreements for the guarantee of payment obligations for various accommodation in Brazil.	**0.4**	0.4
(iv) The Group has received a notice of Infraction from Santos Municipality for BRL$9.1 million, inclusive of fines and interest, relating to ISS (a municipal tax levied on the provision of services) on activities carried out by service providers at the FPSO Itajai. Karoon has rejected the liability and is defending the action.	**1.8**	–

(iv) Block Acquisition

As part of the acquisition of Pacific Exploration and Production Corp's equity interest of Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102, S-M-1165 and S-M-1166 during the 2017 financial year, the Group agreed to pay Pacific Exploration and Production Corp. a deferred contingent consideration of $5.0 million payable on first production reaching a minimum of 1 million barrels of oil equivalent from the Blocks. The deferred contingent obligation has not been provided for as at 31 December 2023, as it is dependent on uncertain future events.

(v) Brazilian Local Content

The Concession Contracts for Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102, S-M-1165, S-M-1537 and S-M-1166 require Karoon Petróleo & Gás Ltda to acquire a minimum proportion of goods and services from Brazilian suppliers, with the objective to stimulate industrial development, promote and diversify the Brazilian economy, encourage advanced technology and develop local capabilities. The minimum Brazilian local content requirement under the Concession Contracts during the exploration and appraisal phase is up to 55%. If Karoon Petróleo & Gás Ltda fails to comply with this minimum requirement, Karoon Petróleo & Gás Ltda may be subject to a fine by the ANP.

(vi) Other Matters

There are also legal claims and exposures, which arise from the Group's ordinary course of business. No material loss to the Group is expected to result.

(b) Contingent Assets

The Group has no contingent assets as at 31 December 2023 (30 June 2023: $Nil).

SECTION E: CAPITAL FUNDING AND RISK MANAGEMENT

NOTE 18. BORROWINGS

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Current		
Syndicated loan facility – secured	**0.1**	–
Total current borrowings	**0.1**	–
Non-current		
Syndicated loan facility – secured	**274.0**	30.0
Less: Transaction costs[i]	**(9.6)**	(1.9)
Total non-current borrowings	**264.4**	28.1
Total borrowings	**264.5**	28.1

(i) Includes remaining unamortised transaction costs associated with the syndicated loan facility.

During the period, Karoon Petróleo e Gás Ltda repaid $29.9 million of the initial $30 million drawn amount. The remaining $0.1 million balance of Karoon's initial US$160 million syndicated loan facility is expected to be repaid during 2024. All other commitments under the initial facility have been cancelled with only the $0.1m outstanding.

In November 2023, Karoon Energy Ltd's wholly owned subsidiaries, KEI (Brazil Santos) Pty Ltd, KEI Finance 1 Pty Ltd and Karoon Petróleo e Gás Ltda (the "Borrowing Base Obligors"), entered into a new committed US$340 million syndicated revolving credit facility with Deutsche Bank AG, ING Belgium SA/NV, Macquarie Bank Limited and Shell Western Supply and Trading Limited. KEI Finance 1 Pty Ltd drew down $274 million on the facility for the Who Dat acquisition funding.

The facility is a reserved based loan, secured against various group assets (including Baúna / Patola) and guaranteed by various Group members.

The new facility bears interest at a rate comprising a benchmark rate of term SOFR plus the applicable margin, and has a maturity date of 30 September 2028, including a scheduled repayment profile subject to customary provisions in respect of remaining reserves of the borrowing base assets.

During the period ended 31 December 2023, there were no new hedges entered into by the Group. In accordance with the terms of the facility agreements both new and old, Karoon enters into hedging arrangements in respect of oil price from time to time over a proportion of production and a period of up to 24 months. Post year end, the Group has entered into Brent oil commodity hedges over 4.26 million barrels from March 2024 to December 2025.

The Group has complied with all loan covenants throughout the reporting period.

NOTE 19. OTHER FINANCIAL ASSETS AND LIABILITIES

The Group's other financial liabilities include derivative financial instruments designated as cash flow hedges, and a derivative financial instrument relating to contingent consideration for the acquisition of an asset.

Derivatives designated as hedging instruments

The Group has entered into derivative financial instruments to hedge its exposure to cash flow risk from movements in oil price (commodity price risk) arising from highly probable forecasted future oil sales. At the inception of a hedge relationship, the Group documents the risk management objective and strategy for undertaking the hedge transaction. The documentation includes identification of the hedging instrument, the hedged item, the nature of the risk being hedged and how the Group will assess whether the hedging relationship meets the hedge effectiveness requirements (including the analysis of sources of hedge ineffectiveness and how the hedge ratio is determined).

Derivative financial instruments are presented as current assets or liabilities to the extent they are expected to be realised or settled within 12 months after the end of the reporting period. Hedges that meet all the qualifying criteria for hedge accounting are accounted for as described below.

Cash flow hedges

When a derivative is designated as a cash flow hedging instrument, the effective portion of changes in the fair value of the derivative is recognised in other comprehensive income ('OCI') and accumulated in the hedging reserve. The effective portion of changes in the fair value of the derivative that is recognised in OCI is limited to the cumulative change in fair value of the hedged item, determined on a present value basis, from inception of the hedge. Any ineffective portion of changes in the fair value of the derivative is recognised immediately in profit or loss. The Group designates only the change in fair value of the spot element of the derivative transaction contracts (the intrinsic value of the option) as the hedging instrument in cash flow hedging relationships. The change in fair value of the value of the option contract in relation to time value of money is separately accounted for as a cost of hedging and recognised in a cost of hedging reserve within equity.

For all financial hedged derivative transaction contracts, the amount accumulated in the hedging reserve and the cost of hedging reserve is reclassified to profit or loss in the same period or periods during which the hedged expected future cash flows affect profit or loss. If the hedge no longer meets the criteria for hedge accounting or the hedging instrument is sold, expires, is terminated or is exercised, then hedge accounting is discontinued prospectively. When hedge accounting for cash flows is discontinued, the amount that has been accumulated in the hedging reserve remains in equity until it is reclassified to profit or loss in the same period or periods as the hedged expected future cash flows affect profit or loss. If the hedged future cash flows are no longer expected to occur, then the amounts that have been accumulated in the hedging reserve and the cost of hedging reserve are immediately reclassified to profit or loss. Further details are disclosed in Note 19.

NOTE 19. OTHER FINANCIAL ASSETS AND LIABILITIES CONTINUED

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Assets		
Current		
Derivative financial instruments – cash flow hedges(i)	**0.2**	3.0
Total assets	**0.2**	3.0
Liabilities		
Current		
Embedded derivative – contingent consideration payable(ii)	**86.0**	86.0
Total current other financial liabilities	**86.0**	86.0
Non-current		
Embedded derivative – contingent consideration payable(ii)	**136.5**	133.0
Total non-current other financial liabilities	**136.5**	133.0
Total other financial liabilities	**222.5**	219.0

(i) The Group has entered into Brent oil price derivative hedges, via a collar structure consisting of bought put and sold call options covering the period from December 2021 to March 2024. The purpose of the hedges is to protect operating cash flows from a portion of crude oil sales against the risk of lower oil prices while retaining significant exposure to oil price upside. The hedges are also a requirement of the syndicated loan facilities (refer to Note 18).

The bought put and sold call options have been designated as cash flow hedges, and in the current period, changes in the fair value of the options and costs of hedging of $3.1m pre-tax ($3m net of tax) have been recognised in the hedging reserves within equity (refer Note 20), which includes $5.9m pre-tax that has been reclassified to profit or loss. No losses were recognised in profit or loss for hedge ineffectiveness during the period.

At 31 December 2023, the Group had the following outstanding hedges:

FINANCIAL PERIOD	BOUGHT PUT STRIKE (US$/BBL)	PUT VOLUME ('000 BBL)	SOLD CALL AVERAGE STRIKE (US$/BBL)	CALL VOLUME ('000 BBL)
2024	65	630	98	423
		630		**423**

(ii) Reconciliation of contingent consideration payable

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Balance at beginning of financial period	**219.0**	298.3
Payments	**–**	(84.5)
Unrealised fair value changes recognised in profit or loss during the period	**3.5**	5.2
Total contingent consideration payable at fair value	**222.5**	219.0

The contingent consideration arrangement for the acquisition of Baúna requires Karoon's wholly owned subsidiary, Karoon Petróleo & Gás Ltda., to pay Petrobras contingent consideration of up to US$285 million.

The contingent consideration accrues interest at 2% per annum from 1 January 2019 with any amounts payable by 31 January after the completion of the relevant testing period. The relevant testing periods are each calendar year from 2022 to 2026 inclusive and are based on the achievement of annual average Platts Dated Brent oil prices thresholds commencing at ≥US$50 and ending at ≥US$70 a barrel.

After the testing of each year, any amount deemed not payable is cancelled and not carried forward. The amount payable each calendar year excluding interest depending on achievement of certain oil prices is disclosed below:

AVERAGE BRENT PRICE (IN US$ UNITS)	CY2022	CY2023	CY2024	CY2025	CY2026	TOTAL
B < 50	–	–	–	–	–	–
50 <= B < 55	3	3	3	2	2	13
55 <= B < 60	17	17	17	8	4	63
60 <= B < 65	34	34	34	15	6	123
65 <= B < 70	53	53	53	24	10	193
B >= 70	78	78	78	36	15	285

At 31 December 2023, based on the Group's internal assessment of future oil prices and industry consensus, the amount payable continues to accrue at the maximum amount payable plus interest. $86.0m, the amount payable in respect of the 2023 calendar year, was paid in January 2024. The fair value of the total amount payable has been revised upwards by $3.5m due to a revision in the discount rate.

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Fair value measurement of financial instruments

When the fair values of financial assets and financial liabilities recorded in the consolidated statement of financial position cannot be measured based on quoted prices in active markets, their fair value is measured using valuation techniques including the discounted cash flow model. The fair value of the contingent consideration (refer to Note 19(ii)) is based on the Group's internal assessment of future oil prices, which considers industry consensus and observable prices, inflation and an appropriate risk-free rate. Changes in assumptions relating to these factors could affect the reported fair value of the financial instrument.

A discount rate of 3.26% and interest per annum of 2% has been applied in the calculation of the present value at 31 December 2023. The fair value of the contingent consideration is estimated by calculating the present value of the future expected cash outflows.

NOTE 20. CONTRIBUTED EQUITY AND RESERVES WITHIN EQUITY

Ordinary shares are classified as equity.

Transaction costs directly attributable to the issue of new ordinary shares, share options or performance rights are shown in equity as a deduction, net of any related income tax, from the proceeds. Transaction costs are the costs that are incurred directly in connection with the issue of new ordinary shares, and which would not have been incurred had those ordinary shares not been issued. These directly attributable transaction costs include registration and other regulatory fees, amounts paid to legal, accounting and other professional advisers, printing costs and marketing costs.

Where the Company acquires its own ordinary shares, as a result of a share buy-back, those ordinary shares are cancelled. No gain or loss is recognised, and the consideration paid to acquire the ordinary shares, including any transaction costs directly attributable, net of any related income tax, is recognised directly as a reduction from equity.

NOTE 20. CONTRIBUTED EQUITY AND RESERVES WITHIN EQUITY CONTINUED

(a) Contributed Equity

	AS AT 31 DECEMBER 2023 NUMBER	AS AT 30 JUNE 2023 NUMBER	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Ordinary shares, fully paid	**801,234,076**	563,359,327	**1,210.8**	907.5
Total contributed equity	**801,234,076**	563,359,327	**1,210.8**	907.5

Ordinary shares have no par value, and the Company does not have a limited amount of authorised capital.

Voting rights of shareholders are governed by the Company's Constitution. In summary, on a show of hands every holder of ordinary shares present at a meeting in person or by proxy is entitled to one vote, and on a poll each such attending shareholder is entitled to one vote for every fully paid ordinary share held.

Ordinary shares participate in dividends as declared from time to time and the proceeds on winding up of the Company in proportion to the number of fully paid ordinary shares held.

(b) Movement in Ordinary Shares

DATE	DETAILS	NOTE	NUMBER OF ORDINARY SHARES	US$M
1 July 2022	Opening balance in previous financial period		558,085,352	907.5
	Performance rights conversion	26(a)	5,273,975	–
30 June 2023	Balance at end of financial period		563,359,327	907.5
27 November 2023	Ordinary shares issued		**188,420,971**	**251.1**
12 December 2023	Ordinary shares issued		**45,922,434**	**61.2**
	Transaction costs arising on ordinary shares issued		**–**	**(9.0)**
	Performance rights conversion	26(a)	**3,531,344**	**–**
31 December 2023	Balance at end of financial period		**801,234,076**	**1,210.8**

(c) Capital Management

The Board of Directors controls the capital of the Company in order to ensure that the Group can fund its operations and continue as a going concern. The aim is to maintain a capital structure that ensures the lowest cost of capital to the Company.

The Chief Executive Officer and Managing Director manages the Company's capital by monitoring future rolling cash flows and adjusting its capital structure, as required, in consultation with the Board of Directors to meet Group business objectives. As required, the Group will balance its overall capital structure through the issue of new ordinary shares, share buy-backs and utilising short-term and long-term loan facilities when necessary.

There were no externally imposed capital management restrictions on the Group during the financial period.

(d) Reserves Within Equity

(i) Share-based Payments Reserve

The share-based payments reserve is used to recognise the grant date fair value of equity-settled share-based payments to Executive Directors, other key management personnel and employees as part of their remuneration, as described in the policy under Note 25 *'Share based payments'*.

(ii) Foreign Currency Translation Reserve

The foreign currency translation reserve is used to recognise exchange differences arising from the translation of financial statements into the presentation currency as described in Note 1(c). The relevant amounts included in the foreign currency translation reserve will be recognised in the consolidated statement of profit or loss and other comprehensive income when each relevant investment in the entity is disposed.

(iii) Hedging Reserves

The Group has entered into Brent oil price derivative hedges. Refer to Note 19(i) for more details.

The Group designates only the change in fair value of the spot element of the derivative transaction contracts (the intrinsic value of the option) as the hedging instrument in cash flow hedging relationships. The change in fair value of the value of the option contract in time is separately accounted for as a cost of hedging and recognised in a cost of hedging reserve within equity.

The following is a reconciliation of the movement of the hedging reserves:

	COST OF HEDGING RESERVE US$M	INTRINSIC VALUE OF OPTIONS US$M	TOTAL HEDGING RESERVES US$M
Balance at beginning of financial period	**(8.0)**	–	**(8.0)**
Change in fair value of cash flow hedges and cost of hedging recognised in OCI	**(2.8)**	–	**(2.8)**
Reclassified from OCI to profit or loss – included in other expenses	**5.9**	–	**5.9**
Deferred tax	**(1.2)**	–	**(1.2)**
Balance at end of financial period	**(6.1)**	–	**(6.1)**

NOTE 21. FINANCIAL RISK MANAGEMENT

The Group's activities expose it to a variety of financial risks: market risk (including foreign exchange risk and interest rate risk), commodity price risk, credit risk and liquidity risk. The Group's overall financial risk management program focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the financial performance of the Group. The Group uses different methods to measure the different types of financial risk to which it is exposed. These methods include sensitivity analysis in the case of foreign exchange, interest rates and commodity prices.

The overall financial risk management strategy of the Group is governed by the Board of Directors through the Audit, Risk and Governance Committee and is primarily focused on ensuring that the Group is able to finance its business plans, while minimising potential adverse effects on financial performance. The Board of Directors provides written principles for overall financial risk management, as well as written policies covering specific areas, such as mitigating foreign exchange, interest rate, commodity price and credit risks, use of derivative financial instruments and investment of excess cash. Financial risk management is carried out by the Company's finance function under policies approved by the Board of Directors. The finance function identifies, evaluates and if necessary, hedges financial risks in close co-operation with the Chief Executive Officer and Managing Director. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and Group activities.

The Group's financial instruments consist of cash and cash equivalents, receivables, security deposits, trade and other payables, lease liabilities, borrowings, derivative financial instruments designated as cash flow hedges, and embedded derivatives.

NOTE 21. FINANCIAL RISK MANAGEMENT CONTINUED

The totals for each category of financial instruments in the consolidated statement of financial position are as follows:

	NOTE	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Financial assets			
Cash and cash equivalents	8	**170.4**	74.8
Receivables	9	**56.4**	71.1
Other financial assets	19	**0.2**	3.0
Total financial assets		**227.0**	148.9
Financial liabilities			
Trade and other payables (refer note (i) below)		**73.8**	61.4
Borrowings (refer note (ii) below)	18	**274.1**	30.0
Other financial liabilities (refer note (iii) below)	19	**222.5**	219.0
Lease liabilities	15	**224.4**	247.6
Total financial liabilities		**794.8**	558.0

(i) Trade and other payables above exclude amounts relating to annual leave liabilities, which are not considered a financial instrument.

(ii) Borrowings exclude transaction costs which are not considered a financial instrument.

(iii) Other financial liabilities relate to the contingent consideration payable to Petrobras as part of the acquisition of Baúna. (refer Note 19(ii)).

(a) Market Risk

(i) Foreign Exchange Risk

Foreign exchange risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. Foreign exchange risk arises when future commercial transactions and recognised financial assets and financial liabilities are denominated in a currency that is not the Company's functional currency.

The Group's revenue, significant operating expenditure including the FPSO charter lease and a large component of capital obligations are predominantly denominated in US$.

The Group's remaining foreign exchange risk exposures relate to administrative and business development expenditures incurred at the corporate level in A$; and operating and capital expenditures incurred by the Group in relation to operating the Baúna production asset in Brazil in Brazilian REAL. These items are translated to US$ equivalents at each period end, and the associated gain or loss is taken to the consolidated statement of profit or loss and other comprehensive income.

The Group manages foreign exchange risk at the corporate level by monitoring forecast cash flows in currencies other than US$ and ensuring that adequate Brazilian REAL and A$ cash balances are maintained. Foreign currencies are bought on the spot market in excess of immediate requirements. Where currencies are purchased in advance of requirements, these balances do not usually exceed 3 months' requirements. The appropriateness of A$ and Brazilian REAL holdings are reviewed regularly against future commitments and current A$ and Brazil REAL market expectations.

Periodically, sensitivity analysis is conducted to evaluate the potential impact of unfavourable exchange rates on the Group's future financial position. The results of this evaluation are used to determine the most appropriate risk mitigation tool to be used. The Group will hedge when it is deemed the most appropriate risk mitigation tool to be used. Foreign currency hedging transactions were not entered into during the financial period or previous financial periods.

The Group is not exposed to material translation exposures at the end of the current financial period as the majority of its financial assets and liabilities are denominated in US$ and as such, no foreign currency sensitivity analysis has been disclosed.

(ii) Interest Rate Risk

Interest rate risk is the risk that the fair value of future cash flows of financial assets and financial liabilities will fluctuate because of changes in market interest rates. Interest rate risk is managed on a Group basis at the corporate level. This risk is managed through the use of cash flow forecasts supplemented by sensitivity analysis.

As at 31 December 2023 and 30 June 2023, there was no interest rate hedging in place.

The Group's interest rate risk arises from long-term borrowings at floating rates and cash and cash equivalents and security deposits which earn interest at floating rates. As long-term borrowings and the majority of cash and cash equivalents are held in US$'s, the primary exposure is to US$ interest rates.

An analysis of the Group's exposure to interest rate risk for financial assets and financial liabilities at the end of the financial period is set out below:

31 DECEMBER 2023	FLOATING INTEREST RATE US$M	FIXED INTEREST RATE US$M	NON-INTEREST BEARING US$M	FAIR VALUE US$M	CARRYING AMOUNT US$M
Financial assets					
Cash and cash equivalents	**164.5**	**5.9**	**–**	**170.4**	**170.4**
Receivables	**–**	**–**	**56.4**	**56.4**	**56.4**
Other financial assets	**–**	**–**	**0.2**	**0.2**	**0.2**
Total financial assets	**164.5**	**5.9**	**56.6**	**227.0**	**227.0**
Financial liabilities					
Trade and other payables	**–**	**–**	**73.8**	**73.8**	**73.8**
Borrowings	**274.1**	**–**	**–**	**274.1**	**274.1**
Other financial liabilities	**–**	**222.5**	**–**	**222.5**	**222.5**
Lease liabilities	**–**	**–**	**224.4**	**224.4**	**224.4**
Total financial liabilities	**274.1**	**222.5**	**298.2**	**794.8**	**794.8**

30 JUNE 2023	FLOATING INTEREST RATE US$M	FIXED INTEREST RATE US$M	NON-INTEREST BEARING US$M	FAIR VALUE US$M	CARRYING AMOUNT US$M
Financial assets					
Cash and cash equivalents	27.0	–	47.8	74.8	74.8
Receivables	–	–	71.1	71.1	71.1
Other financial assets	–	–	3.0	3.0	3.0
Total financial assets	27.0	–	121.9	148.9	148.9
Financial liabilities					
Trade and other payables	–	–	61.4	61.4	61.4
Borrowings	30.0	–	–	30.0	30.0
Other financial liabilities	–	219.0	–	219.0	219.0
Lease liabilities	–	–	247.6	247.6	247.6
Total financial liabilities	30.0	219.0	309.0	558.0	558.0

NOTE 21. FINANCIAL RISK MANAGEMENT CONTINUED

Interest Rate Sensitivity Analysis

The following table details the Group's sensitivity to a 1% p.a. increase or decrease in interest rates, with all other variables held constant. The sensitivity analysis is based on the balance of floating interest rate amounts held at the end of the financial period.

The sensitivity analysis is not fully representative of the inherent interest rate risk, as the financial period end exposure does not necessarily reflect the exposure during the course of a financial period. These sensitivities should not be used to forecast the future effect of movements in interest rates on future cash flows.

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Change in profit(loss) before income tax		
– Increase of interest rate by 1% p.a.	**(1.0)**	–
– Decrease of interest rate by 1% p.a.	**1.0**	–
Change in financial instruments		
– Increase of interest rate by 1% p.a.	**(1.0)**	–
– Decrease of interest rate by 1% p.a.	**1.0**	–

(b) Commodity Price Risk

The Group is exposed to commodity price fluctuations associated with the production and sale of oil. Commodity price risk is managed on a Group basis at the corporate level. To mitigate commodity price risk, during prior periods, the Group entered into Brent oil price cash flow hedges, via a collar structure consisting of bought put and sold call options covering the period from December 2021 to March 2024. During the financial period, approximately 26% of actual production volume was hedged. At reporting date, the Group held hedging financial instruments with a net asset carrying value of $0.2m (refer Note 19). At 31 December 2023, a 10% increase or decrease in the Brent oil price, would have no material impact on the financial statements.

Commodity Price Sensitivity Analysis – Contingent Consideration

As part of the acquisition of Baúna, the Group agreed to pay Petrobras contingent consideration of up to $285 million plus interest of 2% per annum accruing from 1 January 2019. The fair value of the contingent consideration has been accounted for as an embedded derivative and estimated by calculating the present value of the future expected cash outflows. The estimates are based on the Group's internal assessment of future oil prices. A discount rate of 3.26% and inflation factor of 2% has also been applied. Refer to Note 19 for more details.

The following table details the Group's sensitivity to a 10% increase or decrease in its internal assessment of future oil prices on the contingent consideration payable to Petrobras. At 31 December 2023, with the US$70 per barrel threshold triggered over calendar years 2022-2026, the maximum contingent consideration payable has been recognised and as such a 10% increase in the oil price would have no material impact on the financial statements.

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Change in profit/(loss) before income tax		
– Increase of oil price by 10%	**–**	–
– Decrease of oil price by 10%	**21.9**	30.4
Change in financial liabilities		
– Increase of oil price by 10%	**–**	–
– Decrease of oil price by 10%	**(21.9)**	(30.4)

(c) Credit Risk

The maximum exposure to credit risk at the end of the financial period is the carrying amount of the financial assets as disclosed in the consolidated statement of financial position and notes to the consolidated financial statements.

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. Credit risk arises from cash and cash equivalents and security deposits held with banks and financial institutions, as well as credit exposures to customers, including outstanding receivables and refundable tax credits.

Credit risk is managed on a Group basis at the corporate level. To minimise credit risk, the Group has adopted a policy of only dealing with recognised and creditworthy third parties. Receivable balances are monitored on an ongoing basis with the result being the Group's exposure to bad debts is minimised. The Group does not currently hold collateral, nor does it securitise its receivables.

The Group has policies in place to ensure that services are made to customers with an appropriate credit history.

Cash and cash equivalents and security deposit counterparties are limited to credit quality banks and financial institutions. For banks and financial institutions in Australia, only independently rated counterparties with a minimum rating of Aa3/A2 are accepted. For banks and financial institutions in Brazil, only independently rated counterparties with a minimum rating of Baa1 are accepted. For banks and financial institutions in Brazil, with independently rated counterparty ratings below Baa1, exposure cannot exceed the short-term country specific cash requirements unless they are associated banks of an International Bank with a higher credit rating. Cash and cash equivalents are held offshore by the Group's Brazilian subsidiary out of London with an International Bank with a rating of Baa1. The Group's credit exposure and external credit ratings of its counterparties are monitored on a periodic basis. Where commercially practical, the Group seeks to limit the amount of credit exposure to any one bank or financial institution.

(i) Impairment of Financial Assets

The Group has two types of financial assets that are subject to AASB 9 *'Financial Instruments'* 'expected credit loss' model: receivables and security deposits. The Group has applied the AASB 9 general model approach to measure expected credit losses for all receivables and security deposits.

While cash and cash equivalents are also subject to the impairment requirements of AASB 9, the identified impairment loss was considered not significant given the counterparties and/or the short maturity.

Expected Credit Loss

When required, the carrying amount of the relevant financial asset is reduced through the use of a loss allowance account and the amount of any loss is recognised in the consolidated statement of profit or loss and other comprehensive income. When measuring expected credit losses, balances are reviewed based on available external credit ratings, historical loss rates and the days past due.

Receivables

The Group's receivables relating to Brazil and Australia are considered to have low credit risk on the basis that there is a very low risk of default and the debtor has a strong (robust) capacity to meet its obligations in the short-term. The average DPO is 30 to 45 days and the debtor has a healthy credit risk rating. Accordingly, for receivables management has assessed an impairment test using a 12 month expected credit loss model measure and determined that there are no expected credit losses.

As at 31 December 2023, there were $Nil (30 June 2023: $Nil) receivables past due and the loss allowance for receivables recognised during the financial period was $Nil (30 June 2023: $Nil).

(ii) Impairment of Assets (Other than Oil and Gas Assets and Capitalised Exploration and Evaluation Expenditure)

At the end of each reporting period, the Group conducts an internal review of asset values, which is used as a source of information to assess for any indicators of impairment. External factors, such as changes in economic conditions, are also monitored to assess for indicators of impairment. If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated.

NOTE 21. FINANCIAL RISK MANAGEMENT CONTINUED

(d) Liquidity Risk

Liquidity risk is the risk that the Group will encounter difficulty in meeting obligations associated with financial liabilities.

The Group manages liquidity risk by ensuring that there are sufficient funds available to meet financial obligations on a day-to-day basis and to meet unexpected liquidity needs in the normal course of business. Emphasis is placed on ensuring there is sufficient funding in place to meet the ongoing operational requirements of the Group's production activities, exploration, evaluation and development expenditure, and other corporate initiatives.

The following mechanisms are utilised to manage liquidity risk:

- preparing and maintaining rolling forecast cash flows in relation to operational, investing and financing activities;
- comparing the maturity profile of financial liabilities with the realisation profile of financial assets;
- managing credit risk related to financial assets;
- when necessary, utilising short-term and long-term loan facilities;
- investing surplus cash only in credit quality banks and financial institutions; and
- maintaining a reputable credit profile.

At the end of the financial period, the Group held cash and cash equivalents at call of $170.4m (30 June 2023: $74.8m) that are expected to readily generate cash inflows for managing liquidity risk. The Group had external borrowings of $274.1m (30 June 2023: $30.0m).

The Group had access to the following undrawn borrowing facilities at the end of the reporting period:

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
Floating rate		
– Expiring beyond one year (syndicated loan facility and accordion facility)	–	180.0

An analysis of the Group's financial liabilities contractual maturities at the end of the financial period is set out in the tables below. The amounts disclosed in the table are the expected undiscounted cash flows comprising principal repayments.

31 DECEMBER 2023	LESS THAN 6 MONTHS US$M	6-12 MONTHS US$M	1-3 YEARS US$M	3-5 YEARS US$M	OVER 5 YEARS US$M	TOTAL US$M
Financial liabilities						
Non-derivative financial liabilities						
Trade and other payables	67.9	–	5.9	–	–	73.8
Borrowings	0.1	–	91.3	182.7	–	274.1
Lease liabilities	30.0	30.3	119.8	73.2	–	253.3
Derivative financial liabilities						
Contingent consideration – embedded derivative	86.0	–	87.6	58.6	–	232.2
Total financial liabilities	184.0	30.3	304.6	314.5	–	833.4

30 JUNE 2023	LESS THAN 6 MONTHS US$M	6-12 MONTHS US$M	1-3 YEARS US$M	3-5 YEARS US$M	OVER 5 YEARS US$M	TOTAL US$M
Financial liabilities						
Non-derivative financial liabilities						
Trade and other payables	58.4	3.0	10.4	–	–	71.8
Borrowings	–	–	30.0	–	–	30.0
Lease liabilities	30.2	29.9	119.8	103.2	–	283.1
Derivative financial liabilities						
Contingent consideration – embedded derivative	–	86.0	128.8	17.5	–	232.3
Total financial liabilities	88.6	118.9	289.0	120.7	–	617.2

(e) Fair Value Estimation

For disclosure purposes only, the fair values of financial assets and financial liabilities as at 31 December and 30 June 2023 are presented in the table under Note 21(a)(ii) and can be compared to their carrying values as presented in the consolidated statement of financial position. Fair values estimated for disclosure purposes are based on information that is subject to judgement, where changes in assumptions may have a material impact on the amounts estimated.

The following summarises the significant methods and assumptions used in estimating fair values of financial assets and financial liabilities for disclosure purposes:

Cash and Cash Equivalents

The carrying amount is fair value due to the liquid nature of these assets.

Receivables

The carrying amounts of current receivables are assumed to approximate their fair values due to their short-term nature.

Security Deposits

The carrying amounts of security deposits are assumed to represent their fair values based on their likely realisability profile.

Trade and Other Payables

Due to the nature of these financial liabilities, their carrying amounts are a reasonable approximation of their fair values.

Lease Liabilities

Fair value is calculated based on the present value of the lease payments expected to be paid over the lease term, discounted using the interest rate implicit in the lease or, if the rate cannot be readily determined, the Group's estimated incremental borrowing rate.

Derivative Financial Instruments – Cash Flow Hedges

The fair value of derivative financial instruments designated as cash flow hedges are obtained from third party valuations. The fair value is determined using valuation techniques which maximise the use of observable market data.

Other Financial Liabilities – Embedded Derivative

The fair value of the contingent consideration was estimated by calculating the present value of the future expected cash outflows. The estimates are based on the Group's internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts. A discount rate of 3.26% and 2% inflation factor has also been applied.

NOTE 21. FINANCIAL RISK MANAGEMENT CONTINUED

Fair value measurement

The Group uses the following hierarchy for determining and disclosing the fair value of financial instruments by valuation technique in accordance with AASB 13 *'Fair Value Measurement'*:

- Level 1: fair value measurements are those derived from quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2: fair value measurements are those derived from inputs other than quoted prices included within Level 1 which are observable for the asset or liability, either directly or indirectly; and
- Level 3: fair value measurements are those derived from valuation techniques which include inputs for the asset or liability that are not based on observable market data.

All of the Group's financial instruments were valued using the Level 2 valuation technique.

SECTION F: GROUP STRUCTURE

NOTE 22. SUBSIDIARIES

The consolidated financial statements incorporate the assets, liabilities and results of the following subsidiaries in accordance with the accounting policy described throughout the notes.

NAME	COUNTRY OF INCORPORATION OR REGISTRATION	BUSINESS ACTIVITIES CARRIED ON IN	PERCENTAGE OF EQUITY AND VOTING INTERESTS HELD BY THE GROUP AS AT 31 DECEMBER 2023 %	AS AT 30 JUNE 2023 %
Parent Company:				
Karoon Energy Ltd	Australia	Australia		
Unlisted subsidiaries of Karoon Energy Ltd:				
Karoon Energy International Pty Ltd	Australia	Australia	**100**	100
Karoon Gas Browse Basin Pty Ltd	Australia	Australia	**100**	100
Karoon Gas (FPSO) Pty Ltd	Australia	Australia	**100**	100
Unlisted subsidiaries of Karoon Energy International Pty Ltd:				
KEI (Brazil Santos) Pty Ltd	Australia	Australia	**100**	100
Karoon Peru Pty Ltd	Australia	Australia	**100**	100
KEI (Peru Z38) Pty Ltd	Australia	Australia	**100**	100
A.C.N. 672 679 793 Pty Ltd	Australia	Australia	**100**	–
Unlisted subsidiaries of KEI (Brazil Santos) Pty Ltd:				
KEI Finance 1 Pty Ltd	Australia	Australia	**100**	–
Karoon Petróleo & Gás Ltda	Brazil	Brazil	**100**	100
Branch of KEI (Peru Z38) Pty Ltd:				
KEI (Peru Z38) Pty Ltd, Sucursal del Peru	Peru	Peru	**100**	100
Unlisted subsidiary of A.C.N. 672 679 793 Pty Ltd				
KUSA Inc.	USA	USA	**100**	–

NOTE 23. PARENT COMPANY FINANCIAL INFORMATION

The financial information for the Parent Company, Karoon Energy Ltd, has been prepared on the same basis as the consolidated financial statements, except as set out below:

Investments in Subsidiaries

The Parent Company does not designate any investments in subsidiaries as being subject to the requirements of Australian Accounting Standards specifically applicable to financial instruments. They are held for strategic and not trading purposes.

Share-based Payments

The grant by the Company of equity-settled performance rights over its ordinary shares to the employees of subsidiary companies in the Group is treated as a capital contribution to that subsidiary company. The fair value of employee services received, measured by reference to the grant date fair value, is recognised over the vesting period as an increase to investments in subsidiaries, with a corresponding credit to equity.

(a) Summary Financial Information

The individual financial statements for the Parent Company show the following aggregate amounts:

	AS AT 31 DECEMBER US$M	AS AT 30 JUNE US$M
Statement of financial position		
Current assets	**31.9**	32.8
Non-current assets	**478.9**	168.9
Total assets	**510.8**	201.7
Current liabilities	**9.9**	4.7
Non-current liabilities	**0.1**	0.2
Total liabilities	**10.0**	4.9
Net assets	**500.8**	196.8
Contributed equity	**1,210.8**	907.5
Accumulated losses	**(620.7)**	(663.9)
Share-based payments reserve	**57.7**	56.4
Foreign currency translation reserve	**(147.0)**	(103.2)
Total equity	**500.8**	196.8
Profit/(loss) for financial period	**(21.9)**	(10.5)
Total comprehensive profit/(loss) for financial period	**0.5**	(15.7)

(b) Contingent Liabilities of Parent Company

	AS AT 31 DECEMBER US$M	AS AT 30 JUNE US$M
(i) Bank guarantees were provided in respect of property lease rental agreements. These guarantees may give rise to liabilities in the Parent Company if obligations are not met under these guarantees. The bank guarantees given to lessors are fully funded by way of payment of security deposits.	**0.2**	0.2
(ii) The Company's present intention is to provide the necessary financial support for all Australian incorporated subsidiaries, whilst they remain wholly owned subsidiaries, as is necessary for each company to pay all debts as and when they become due.		

(c) Guarantees Entered into by Parent Company

- A Parent Company guarantee totalling BRL$117.7 million (US$24.3 million equivalent as at 31 December 2023) was provided to the ANP in respect of existing decommissioning obligations relating to the Baúna field. A surety bond has been issued to the ANP to replace this Parent Company guarantee. Management expect the Parent Company guarantee to be released in the first half of 2024.
- Parent Company guarantees have been provided to the ANP guaranteeing a subsidiary's obligations under Concession Agreements covering Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102 and S-M-1537 in Brazil.

NOTE 24. ASSET ACQUISITION

Karoon completes acquisition of interests in the US Gulf of Mexico (GoM)

Karoon successfully completed the acquisition of interests in the US GoM from LLOG Exploration Offshore, LLC and LLOG Omega Holdings (collectively referred to as "LLOG"), on 21 December 2023. The acquisition comprises a 30% working interest in the Who Dat and Dome Patrol fields, including the associated infrastructure, ~16% working interest in the Abilene field and varying interests in adjacent exploration acreage.

Upon completion, Karoon transferred US$684 million to LLOG. This amount consisted of the initially agreed purchase price of US$720 million less the US$36 million deposit which had already been paid. The final payment for the purchase was funded by a US$274 million drawdown from the company's newly sanctioned US$340 million debt facility, US$312 million attained from a fully-underwritten equity issue, and the remainder from existing cash reserves.

The purchase price of US$720m, less estimated completion price adjustments of $0.2m[1], has been allocated to the acquired assets and liabilities based on their relative fair values as follows:

	NOTE	US$M
Oil and gas assets	12	**696.9**
Provision for restoration	16(b)	**(60.1)**
Exploration and evaluation assets	13	**83.0**
Net purchase price paid		**719.8**

1. The estimated completion price adjustment is subject to review and finalisation. Under the purchase and sale agreement, LLOG (the seller) has 180 days after the financial close date to prepare the "Final Settlement Statement". Karoon in turn has 60 days to respond and agree.

The acquisition includes the following equity interests in joint operations:

		UNINCORPORATED EQUITY NET WORKING INTEREST (%)			
FIELD	LOCATION	DEC 23	JUN 23	PRINCIPAL ACTIVITIES	OPERATOR OF JOINT OPERATION
Who Dat	US Gulf of Mexico	30	–	Producing and Developing Assets	LLOG
Dome Patrol	US Gulf of Mexico	30	–	Producing and Developing Assets	LLOG
Abilene	US Gulf of Mexico	~16	–	Producing and Developing Assets	LLOG
Who Dat East	US Gulf of Mexico	40	–	Exploration and evaluation	LLOG
Who Dat South	US Gulf of Mexico	30	–	Exploration and evaluation	LLOG
Who Dat West	US Gulf of Mexico	35	–	Exploration and evaluation	LLOG

SECTION G: ADDITIONAL INFORMATION

NOTE 25. COMMITMENTS

	AS AT 31 DECEMBER 2023 US$M	AS AT 30 JUNE 2023 US$M
(a) Capital and Service Expenditure Commitments		
Contracts for capital and service expenditure in relation to assets not provided for in the consolidated financial statements and payable.		
Capital commitments		
Not later than one year	**16.1**	4.4
Later than one year but not later than five years	**–**	–
Total capital commitments	**16.1**	4.4
Service commitments		
Service commitments predominantly relating to the services contract with the FPSO operator (separate from charter lease of FPSO asset), with a daily rate for operations payable under the contract.		
Not later than one year	**16.8**	14.1
Later than one year but not later than five years	**15.3**	22.2
Total service commitments	**32.1**	36.3
Total capital and service expenditure commitments	**48.2**	40.7
(b) Exploration Expenditure Commitments		
The Group has guaranteed commitments for exploration expenditure arising from obligations to governments to perform minimum exploration and evaluation work and expend minimum amounts of money pursuant to the award of exploration tenement Blocks S-M-1537, S-M-1356 and S-M-1482, (30 June 2023: Block S-M-1537) not provided for in the consolidated financial statements and payable.		
Not later than one year(i)	**5.0**	–
Later than one year but not later than five years	**22.5**	3.5
Total guaranteed exploration expenditure commitments	**27.5**	3.5

(i) The Group was successful in securing two deepwater blocks (S-M-1356 and S-M-1482) in the ANP 4th permanent offer round during December 2023. The payment of the bid bonus for these blocks is expected to occur in Q2 CY24.

Note, the figures above do not include any commitments in relation to Exploration Blocks S-M-1037 and S-M-1101 relating to the Neon and Goiá light oil discoveries. In accordance with Brazilian regulatory requirements, during January 2019 Karoon submitted both a Final Discovery Evaluation Report and Declaration of Commerciality for the discoveries. This transitioned the Blocks for Brazilian regulatory requirements, from the exploration phase to the development phase. However, it does not mean that Karoon has reached, nor is compelled to reach, a final investment decision ('FID') to proceed into a Development of the discoveries.

Estimates for future exploration expenditure commitments to the government are based on estimated well and seismic costs, which will change as actual drilling locations and seismic surveys are completed and are calculated in current dollars on an undiscounted basis. The exploration and evaluation obligations may vary significantly as a result of renegotiations with relevant parties.

NOTE 26. SHARE-BASED PAYMENTS

Share-based remuneration benefits are provided to Executive Directors and employees via the Company's PRP. The Group issues equity-settled and cash-settled share-based payments to certain employees.

The fair value of performance rights granted is recognised as a share-based payments expense in the consolidated statement of profit or loss and other comprehensive income. The total amount to be expensed is determined by reference to the fair value of the performance rights granted, which includes any market performance conditions, but excludes the impact of any service and non-market performance vesting conditions. Non-market performance vesting conditions are included in assumptions about the number of performance rights that are expected to vest.

The fair value is measured at grant date. For equity-settled share-based payments the corresponding credit is recognised directly in the share-based payments reserve in equity. For cash-settled share-based payments a liability is recognised based on fair value of the payable earned by the end of the reporting period. The liability is re-measured to fair value at each reporting date up to, and including the vesting date, with changes in fair value recognised in share-based payments expense. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied. At the end of each reporting period, the Group revises its estimates of the number of performance rights that are expected to vest based on the non-market performance vesting conditions. It recognises the impact of the revision to original estimates, if any, in the consolidated statement of profit or loss and other comprehensive income.

The fair value of performance rights, granted for $nil consideration, at grant date is based on the Company's closing share price at that date, with the exception of long-term performance rights granted during the current financial period.

Long term performance rights granted during the current financial period, which are subject to market-based performance conditions, have been valued using a Monte Carlo simulation approach.

The share-based payment plans are described below. There has been no cancellation to a plan during the financial period.

KEY ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Share-based Payments

Estimating fair value for share-based payment transactions requires determination of the most appropriate valuation model, which depends on the terms and conditions of the grant. This estimate also requires determination of the most appropriate inputs to the valuation model including the expected life of the performance right, volatility and dividend yield and making assumptions about them at grant date. The fair value of long-term performance rights issued during the current financial year are valued using a Monte Carlo simulation approach taking into account the terms and conditions on which the performance rights were granted.

The cumulative share-based payments expense recognised reflects the extent, in the opinion of management, to which the vesting period has expired and the number of and performance rights granted that will ultimately vest or be settled in cash. At the end of each reporting period, the unvested performance rights and cash-settled share-based payment liability are adjusted by the number forfeited during the reporting period to reflect the actual number of performance rights outstanding and cash liability to be settled. In addition, the fair value of cash-settled share-based payments are remeasured, up to the date of settlement, to reflect the cash liability at the end of each reporting period with changes in the fair value recognised in the profit or loss.

(a) Performance Rights Plan ('PRP')

The Company currently has two PRPs in place, the 2019 PRP and 2022 PRP. The 2022 PRP was approved by shareholders at the 2022 Annual General Meeting.

Under the PRP, eligible employees are offered performance rights, which subject to performance conditions, can on exercise be converted to fully paid ordinary shares in the Company, or equivalent cash value, for no consideration provided certain conditions have been met. Vesting of STI performance rights is conditional on the achievement of performance measures, over a one-year performance period, and provided the employee remains employed by the Company for an additional year. Vesting of LTI performance rights is conditional on the achievement of performance measures over a three-year performance period. In each case, the Board, on advice from the People and Culture Committee, will be responsible for assessing whether the performance measures have been achieved. When vested, each performance right is, subject to exercise, convertible into one ordinary share of the Company.

Performance rights granted carry no dividend or voting rights.

If there is a change of control of the Company, for all unexercised performance rights issued pursuant to the Company's PRP, a percentage amount of unvested performance rights may vest on the basis of the pro-rata achievement of pre-determined performance conditions.

NOTE 26. SHARE-BASED PAYMENTS CONTINUED

During the financial period, the Group granted 296,634 performance rights (30 June 2023: 495,468) over unissued ordinary shares in the Company to the Chief Executive Officer and Managing Director. The performance rights were provided to the Chief Executive Officer and Managing Director and were subject to approval by shareholders at the 2023 Annual General Meeting. Performance rights issued to Directors are approved on a case-by-case basis by shareholders at relevant general meetings.

The following summary reconciles the outstanding performance rights over unissued ordinary shares in the Company at the beginning and end of the financial period:

	6 MONTHS ENDED 31 DECEMBER 2023 NUMBER	12 MONTHS ENDED 30 JUNE 2023 NUMBER
Balance at beginning of financial period	**9,063,068**	13,645,295
Granted during financial period	**1,257,634**	2,813,925
Vested and converted during financial period	**(3,531,344)**	(5,273,975)
Cash-settled during financial period	**(914,161)**	(1,326,032)
Forfeited during financial period	**(166,598)**	(796,145)
Balance at end of financial period	**5,708,599**	9,063,068
Vested and exercisable at end of financial period	**177,689**	–

(i) The weighted average fair value of performance rights granted during the financial period was A$1.54 (30 June 2023: A$1.68). Fair values of STI performance rights were based on the Company's closing share price at grant date whereas LTI performance rights were based on a Monte Carlo simulation valuation at grant date. Refer to details at Note 26(b) below.

(ii) The weighted average exercise price of performance rights converted during the financial year was A$Nil (2023: A$Nil).

Performance rights issued during the financial period were issued under the 2022 PRP.

Performance rights outstanding as at 31 December 2023 had a weighted average remaining contractual life of 791 days (30 June 2023: 635 days). Details of performance rights outstanding at the end of the financial year are:

GRANT DATE	DATE OF EXPIRY	NUMBER
25 September 2020	30 June 2024	**153,704**
23 March 2022	30 June 2025	**872,085**
6 May 2022	30 June 2025	**1,246,439**
24 November 2022	30 June 2026	**432,577**
16 December 2022	30 June 2024	**23,985**
16 December 2022	30 June 2026	**1,616,614**
31 March 2023	30 June 2026	**105,561**
14 November 2023	30 June 2025	**57,263**
23 November 2023	30 June 2026	**12,649**
23 November 2023	30 June 2025	**261,135**
23 November 2023	30 June 2027	**926,587**
Total performance rights		**5,708,599**

(b) Fair Value of Performance Rights

The fair value of each LTI performance right issued during the financial period was estimated on grant date using the Monte Carlo valuation methodology. The Monte Carlo valuation methodology takes into account the exercise price, the term of the performance right, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the performance right. The fair value of STI performance rights issued during the current or previous financial periods were based on the Company's closing share price at grant date.

The Group applied the following assumptions and inputs in estimating the weighted average fair value for LTI performance rights:

	6 MONTHS ENDED 31 DECEMBER 2023	12 MONTHS ENDED 30 JUNE 2023
Weighted average exercise price	**$A Nil**	$A Nil
Weighted average life of performance rights	**1,310 days**	1,172 days
Weighted average share price	**A$2.12**	A$2.18
Expected share price volatility	**44.71%**	48.40%
Risk free interest rate	**4.34%**	3.70%
Dividend yield	**1.36%**	1.39%
Weighted average performance rights value	**A$1.32**	A$1.58

Historical volatility was the basis for determining expected share price volatility as it is assumed that this is indicative of future trends, which may not eventuate.

(c) Share-based Payments Expense

Total expenses arising from share-based payment transactions recognised during the financial period, included as part of other expenses in the consolidated statement of profit or loss and other comprehensive income, were as follows:

	6 MONTHS ENDED 31 DECEMBER 2023 US$M	12 MONTHS ENDED 30 JUNE 2023 US$M
Share-based payments expense (non-cash)	**1.3**	2.6
Share-based payments expense (cash-settled)	**0.1**	0.5
Total share-based payments expense	**1.4**	3.1

NOTE 27. RELATED PARTY TRANSACTIONS

Transactions between related parties are on normal commercial terms and conditions, no more favourable than those available to other parties, unless otherwise stated.

(a) Subsidiaries

Interests in subsidiaries are set out in Note 22.

During the financial period, the Parent Company provided accounting, administrative and technical services to subsidiaries at cost or at cost plus a mark-up where required under relevant tax transfer pricing legislation. These allocations were based on costs recharged on a relevant time allocation of employees and consultants and associated office charges.

Other transactions that occurred were provision of funding by the Parent Company to its overseas subsidiaries via an increase in contributed equity and intercompany loans to the Australian subsidiaries. The intercompany loans provided are at a Nil% interest rate (30 June 2023: Nil%) and no fixed term for repayment and therefore will not be repaid within 12 months. Loans are unsecured and are repayable in cash.

Where equity-settled performance rights are issued to employees of subsidiaries within the Group, the transaction is recognised as an investment in the subsidiary by the Parent Company and in the subsidiary, a share-based payments expense and an equity contribution by the Parent Company.

The above transactions are eliminated on consolidation.

(b) Remuneration of Key Management Personnel

Directors and other key management personnel remuneration is summarised as follows:

	6 MONTHS ENDED 31 DECEMBER 2023 US$000	12 MONTHS ENDED 30 JUNE 2023 US$000
Short-term employee benefits	**1,548**	2,431
Post-employment benefits	**130**	197
Long-term employee benefits (non-cash)	**(9)**	79
Termination benefits	**232**	–
Share-based payments expense	**668**	1,193
Total key management personnel remuneration	**2,569**	3,900

Detailed remuneration disclosures for the Directors and other key management personnel are provided in Section 10 of the audited Remuneration Report on pages 46 to 53. Termination of the Executive Director's and other key management personnels' employment is subject to a minimum notice period as disclosed on page 44 of the audited Remuneration Report.

Apart from the details disclosed in this note, no Director or other key management personnel has entered into a material contract with the Group since the end of the previous financial year and there were no material contracts involving Directors' or other key management personnel interests subsisting as at 31 December 2023.

(c) Other Transactions with Directors and Other KMP

During the financial period, the Group paid US$132,213 to Radix Engenharia e Software (Radix), an entity of which Mr Tadeu Fraga, a Non-Executive Director, is a Board member. Radix provided engineering consulting services to the Group at market prices. Mr Fraga's interest in Radix commenced on 1 March 2023, post the execution of the contract.

During the financial period, Ms Fraga, a family member of Mr Tadeu Fraga, a Non-Executive Director, remained employed by the Group as P&C Co-ordinator in Brazil. The total value of her remuneration (including share-based payments expense) during the financial period was US$67,232. Ms Fraga's employment with the Karoon Group commenced prior to the appointment of Mr Fraga.

NOTE 28. REMUNERATION OF EXTERNAL AUDITORS

	6 MONTHS ENDED 31 DECEMBER 2023 US$'000	12 MONTHS ENDED 30 JUNE 2023 US$'000
The auditor of Karoon Energy Ltd is PricewaterhouseCoopers.		
Remuneration received or due and receivable by the external auditors of the Company for:		
– Audit and review of financial statements of Karoon Energy Ltd Group (PricewaterhouseCoopers Australia)	**173**	190
– Audit and review of financial statements of controlled entities (Related Practices of PricewaterhouseCoopers Australia)	**109**	151
Sub-total	**282**	341
Other assurance services	**51**	27
Total remuneration for external auditors(i)	**333**	368

(i) The group and its controlled entities have not procured any 'Other services' from the external auditors other than those included above under 'Other assurance services'.

NOTE 29. SUBSEQUENT EVENTS

This Annual Report was authorised for issue by the Board of Directors on 29 February 2024. The Board of Directors has the power to amend and reissue the consolidated financial statements and notes.

Since 31 December 2023, there have been no material events that have occurred.

DIRECTORS' DECLARATION

The Directors' declare that:

(a) in the Directors' opinion, the consolidated financial statements and notes, set out on pages 56 to 107 are in accordance with the *Corporations Act 2001*, including:

   (i) complying with relevant Australian Accounting Standards and the *Corporations Regulations 2001*; and

   (ii) giving a true and fair view of the Group's financial position as at 31 December 2023 and of its performance for the financial period ended on that date; and

(b) in the Directors' opinion, there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

Note 1(a) confirms that the consolidated financial statements also comply with International Financial Reporting Standards as issued by the International Accounting Standards Board.

The Directors have been given the declarations by the Chief Executive Officer and Managing Director, and Executive Vice President and Chief Financial Officer required by Section 295A of the *Corporations Act 2001*.

This Directors' Declaration is made in accordance with a resolution of the Directors.

On behalf of the Directors:

Mr Peter Botten
Independent Non-Executive Chairman

Dr Julian Fowles
Chief Executive Officer and Managing Director

29 February 2024

Independent auditor's report

To the members of Karoon Energy Ltd

Report on the audit of the financial report

Our opinion

In our opinion:

The accompanying financial report of Karoon Energy Ltd (the Company) and its controlled entities (together the Group) is in accordance with the *Corporations Act 2001*, including:

(a) giving a true and fair view of the Group's financial position as at 31 December 2023 and of its financial performance for the period 1 July 2023 to 31 December 2023

(b) complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

What we have audited

The Group financial report comprises:

- the consolidated statement of financial position as at 31 December 2023
- the consolidated statement of profit or loss and other comprehensive income for the period 1 July 2023 to 31 December 2023
- the consolidated statement of changes in equity for the period 1 July 2023 to 31 December 2023
- the consolidated statement of cash flows for the period 1 July 2023 to 31 December 2023
- the notes to the consolidated financial statements, including material accounting policy information and other explanatory information
- the directors' declaration.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional & Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

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Our audit approach

An audit is designed to provide reasonable assurance about whether the financial report is free from material misstatement. Misstatements may arise due to fraud or error. They are considered material if individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

We tailored the scope of our audit to ensure that we performed enough work to be able to give an opinion on the financial report as a whole, taking into account the geographic and management structure of the Group, its accounting processes and controls and the industry in which it operates.

Audit Scope

- Our audit focused on where the Group made subjective judgements, for example, significant accounting estimates involving assumptions and inherently uncertain future events.
- In establishing the overall approach to the Group audit, we determined the type of work that needed to be performed by us, as the Group engagement team, and by component auditors under our instruction.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report for the current period. The key audit matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. Further, any commentary on the outcomes of a particular audit procedure is made in that context. We communicated the key audit matters to the Audit, Risk and Governance Committee.

Key audit matter	*How our audit addressed the key audit matter*
Accounting for the acquisition of interests in the US Gulf of Mexico *(Refer to note 24)* During the period, the Group acquired interests in the US Gulf of Mexico for a total consideration of US$720 million. The accounting for the acquisition of these interests was a key audit matter due to the significance of the related balances, and because of the judgement involved in the Group determining whether the acquisition should be treated as an asset acquisition or a business combination under the requirements of Australian Accounting Standards.	We performed the following procedures, amongst others, in relation to this key audit matter: • Obtained and read the Purchase and Sale Agreement and Offshore Operating Agreements to develop an understanding of the relevant terms and conditions of these agreements. • Evaluated the Group's assessment that the acquisition of these interests met the criteria for an asset acquisition in line with the requirements of Australian Accounting Standards. • Assessed the recognition and measurement of the material assets and liabilities related to the acquisition in line with the requirements of Australian Accounting Standards. • Considered the reasonableness of the related disclosures in line with the requirements of Australian Accounting Standards.

Key audit matter	How our audit addressed the key audit matter
Assessing the carrying value of oil and gas assets *(Refer to note 12)* As at 31 December 2023, the Group's consolidated statement of financial position includes oil and gas assets of US$1,391 million. Group policy is to assess for indicators of impairment annually or more frequently if indicators of impairment exist. Assessing the carrying value of oil and gas assets was a key audit matter because of the judgement involved in the Group assessing impairment indicators and the financial significance of oil and gas assets.	To assess the carrying value of oil and gas assets, we performed the following procedures, amongst others: • Evaluated the Group's assessment of whether there were any indicators of asset impairment, including consideration of movement in oil prices, reserves and resources and asset performance over the period. • Compared the value of the net assets of the Group at year end to its market capitalisation as at 31 December 2023.

Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report for the period 1 July 2023 to 31 December 2023, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and accordingly we do not express any form of assurance conclusion thereon through our opinion on the financial report. We have issued a separate opinion on the remuneration report.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website at: https://www.auasb.gov.au/admin/file/content102/c3/ar1_2020.pdf. This description forms part of our auditor's report.

Report on the remuneration report

Our opinion on the remuneration report

We have audited the remuneration report included in the directors' report for the period 1 July 2023 to 31 December 2023.

In our opinion, the remuneration report of Karoon Energy Ltd for the period 1 July 2023 to 31 December 2023 complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the remuneration report in accordance with section 300A of *the Corporations Act 2001*. Our responsibility is to express an opinion on the remuneration report, based on our audit conducted in accordance with Australian Auditing Standards.

PricewaterhouseCoopers

PricewaterhouseCoopers

Graeme McKenna

Graeme McKenna
Partner

Melbourne
29 February 2024

REMUNERATION REPORT

Dear Shareholders,

On behalf of the Board of Directors I am pleased to present to you the Karoon Energy Ltd Remuneration Report for the financial year ended 30 June 2023.

Overview

Karoon's strategy and remuneration structure is designed to link remuneration outcomes to shareholder value. We believe it has achieved this for FY23 by rewarding the achievement of significant operational and strategic goals, while also accounting for the underperformance on production arising from the un-scheduled FPSO shutdown in March – May 2023.

In determining the remuneration outcomes for employees and executives, the Board has considered the overall performance of Karoon and individual executives having regard to the specific goals and objectives set at the beginning of FY23. A key aspect of the overall remuneration approach has been assessment against the measurable objectives set out in the Corporate Scorecard, which is disclosed within the Remuneration Report.

Overview of 2023 Financial Year Remuneration Outcomes

In respect of FY23, Karoon's key remuneration outcomes were:

Total Remuneration of executives	INCREASED	Total remuneration was increased for all executive KMP following an external benchmarking exercise undertaken in January 2023.
Short Term Incentive ("STI")	STI PARTLY AWARDED	60% of the Corporate Scorecard component of the STI was achieved. Individual STI outcomes for KMPs were as follows: 60% CEO/MD and 58% and 65% respectively for the other KMP. In respect of executives, the STI is to be paid 50% in cash and 50% in the form of a grant of performance rights with such rights to be (a) issued after the release of the Company's FY2023 full year financial results and (b) subject to a retention period. Details of performance rights are set out on page 52.
Long term Incentive ("LTI")	LTI AWARDED	100% of the 2021 LTI was awarded in respect of the three-year performance period from 1 July 2020 to 30 June 2023. In respect of the performance period, Karoon was at the 80th percentile, achieving a TSR of 49.1% when compared against the relevant industry peer group.
Board and committee fees	INCREASED	Board and Committee fees paid to the Non-Executive Chair and Non-Executive Directors were increased by 5%, while the fees paid to the Chairs of Board committees was increased by A$5,000 per annum. This was exclusive of the 0.5% superannuation guarantee increase.
2022 AGM Remuneration Report	'99.44%' YES VOTE	Karoon received more than 99.44% of 'yes' votes on a poll to adopt its Remuneration Report for the 2022 financial year. No specific feedback on Karoon's remuneration practices was received at the 2022 Annual General Meeting.

Detailed explanations in respect of the above are set out in the disclosures within the remuneration report.

No board discretion was exercised in relation to FY23 remuneration outcomes.

Remuneration Strategy and Guiding Principles

Karoon's guiding principles for its remuneration framework are as follows:

- **Safety, culture and ethics:** ensuring that clear vesting gateways exist based on appropriate safety and ethical outcomes. If outcomes do not meet the relevant standards, these gateways will block "at-risk" remuneration payments.
- **Shareholder value is paramount:**
  - remuneration outcomes (particularly incentive-based outcomes) are designed to take account of share price movements across the performance period and therefore, the value delivered to shareholders;
  - a close alignment is created between operational performance, delivery of corporate objectives, rewards and sustained growth in shareholder value; and
  - as Karoon has now transitioned from explorer to producer, it is recognised that capital management initiatives should also now be considered.

- **People:**
  - remuneration and people issues are considered by the People and Culture Committee of the Board and environmental and social issues by the Sustainability and Operational Risk Committee of the Board. Nonetheless, all relevant decision-making and associated discussion remains the responsibility of the Board;
  - our remuneration structures are designed to attract, motivate and retain the best people while remunerating them reasonably and competitively; and
  - we encourage our people to hold equity in Karoon which builds a culture of viewing management decisions as an owner, thereby helping to further align executives' and shareholders' interests. In relation to this, during 2023, the new management shareholding policy was reviewed and reconfirmed. Under the policy, KMP are now required to maintain a shareholding in the Company equal to 50% of their first year, fixed remuneration (after-tax) within three years of their initial appointment.
- **Environment, Social and Governance (ESG):** ESG considerations are integrated into our remuneration structures. In FY23, several STI hurdles were included as part of the Corporate Scorecard. These goals related to our people, emissions reduction activities in our operations and pursuing carbon sequestration projects of scale as part of Karoon's overall business strategy.
- **Transparency:** remuneration measures, outcomes and reporting are as simple and transparent as possible for shareholders and other stakeholders.

TY23 Financial Year Remuneration Settings

Looking ahead to the transitional financial year for the six months to 31 December 2023, the underlying remuneration structure and approach to setting incentives for Australian and Brazilian staff members will remain consistent, with the Board, aided by the People and Culture Committee, determining the appropriateness of the remuneration outcomes for TY23.

As always, we will continue to engage with our shareholders, proxy advisors and our wider group of stakeholders to seek feedback so we can continue to refine and improve our remuneration framework and the associated disclosures.

Yours sincerely

Mr Peter Turnbull AM
Chair, People and Culture Committee

23 August 2023

Section 1. Introduction

The Board of Directors is pleased to provide Karoon's Remuneration Report, which details the remuneration for its KMP, defined as those persons having the authority and responsibility for planning, directing and controlling, directly or indirectly, the activities of the Group.

For the financial year ended 30 June 2023, KMP disclosed in the Remuneration Report are as follows:

NAME	POSITION	TERM AS KMP
Executive Directors		
Dr Julian Fowles	Chief Executive Officer and Managing Director	Full financial year
Non-Executive Chairman		
Mr Bruce Phillips	Independent Non-Executive Chairman	Full financial year
Non-Executive Directors		
Ms Luciana Rachid	Independent Non-Executive Director	Full financial year
Mr Clark Davey	Independent Non-Executive Director	Full financial year
Mr Peter Turnbull	Independent Non-Executive Director	Full financial year
Mr Peter Botten	Independent Non-Executive Director	Full financial year
Mr Tadeu Fraga	Independent Non-Executive Director	Commenced 26 August 2022
Other KMP		
Mr Ray Church	Executive Vice President and Chief Financial Officer	Full financial year
Mr Antonio Guimarães	Executive Vice President and President Karoon Brazil	Full financial year

For the purposes of the Remuneration Report:

(i) 'executive' means the Chief Executive Officer and Managing Director and other KMP of the Group;

(ii) 'fixed remuneration' has the meaning given on page 51;

(iii) 'other KMP' means those KMP referred to above under the heading 'Other KMP';

(iv) 'other benefits' has the meaning given on page 51;

(v) 'total remuneration' means fixed remuneration plus variable remuneration; and

(vi) 'variable remuneration' means STI and LTI.

The Remuneration Report for the financial year ended 30 June 2023 outlines the remuneration arrangements of KMP of the Group in accordance with the requirements of the *Corporations Act 2001* and its regulations. The information provided in this Remuneration Report has been audited by Karoon's external auditor, as required by Section 308(3C) of the *Corporations Act 2001*. The Remuneration Report forms part of this Directors' Report.

Section 2. Board and People and Culture Committee Oversight

To assist in ensuring good remuneration governance at Karoon, the Board of Directors established a People and Culture Committee that provides oversight and recommendations to the Board on the remuneration arrangements for sub-CEO executives.

The People and Culture Committee currently consists of a majority of independent Non-Executive Directors and is responsible for reviewing and making recommendations to the Board of Directors regarding (among other things):

- the quantum of sub-CEO executive remuneration;
- the sub-CEO executive remuneration framework, including the operation of, and performance-based outcomes under, Karoon's share-based incentive schemes; and
- the recruitment, retention and termination policies and procedures for sub-CEO executives.

The Board of Directors, assisted by the People and Culture Committee, conducts remuneration reviews for its Non-Executive Chair, Non-Executive Directors, executives and all employees to ensure that remuneration remains market competitive, fair and aligned with both market practice and the best interests of shareholders.

The Board is responsible for all aspects of the remuneration of the CEO and Managing Director.

Further information on the role and responsibilities of the People and Culture Committee is contained in the People and Culture Committee Charter, which can be found under the Governance tab on Karoon's website at www.karoonenergy.com.au.

Share Trading Policy

The trading of ordinary shares by Non-Executive Directors and executives is subject to, and conditional on, compliance with Karoon's Share Trading Policy.

Under Karoon's Share Trading Policy, an individual may not limit his or her exposure to risk in relation to securities (including performance rights). Directors and executives are prohibited from entering into any hedging arrangements over unvested share options or performance rights under Karoon's share-based remuneration schemes.

Karoon monitors compliance with its Share Trading Policy.

To gain approval to trade and ensure that trading restrictions are not in force, any employee, contractor or other designated person wishing to trade in Karoon securities must consult the Company Secretary, while the Executive Vice President and President Karoon Brazil, the Company Secretary or any Director wishing to trade in Karoon securities must consult the Chair, and the Chair must consult and seek approval of the Audit, Risk and Governance Committee Chair. All trades by Directors and executives during the financial year ended 30 June 2023 were conducted in compliance with Karoon's Share Trading Policy.

Karoon's Share Trading Policy can be found under the Governance tab on Karoon's website at www.karoonenergy.com.au.

Karoon has a minimum shareholding policy which applies to both Non-Executive Directors and executives.

Section 3. How does Karoon make decisions about remuneration

The Board of Directors has developed a remuneration policy that ensures executive remuneration supports the current business strategy and needs of the business. In particular, the decision to use performance tested share-based remuneration (in addition to cash-based incentive payments) for its incentive plans reflects the Board of Directors' belief that this best aligns executive and shareholder interests in the short and long-term. Karoon's success is measured by the delivery of its strategic objectives in the short-term and a clear demonstration of shareholder value creation in the long-term through share price growth.

Broadly, the objectives of Karoon's executive remuneration framework are to ensure:

- remuneration is reasonable and competitive in order to attract, retain and motivate talented and high calibre executives capable of managing Karoon's diverse international operations;
- remuneration is set at a level acceptable to shareholders, having regard to Karoon's performance, and rewards individual achievements;
- remuneration structures create alignment between performance, reward and sustained growth in shareholder value;
- remuneration outcomes provide recognition of contribution to overall long-term growth in the value of Karoon's asset portfolio and are transparent to both participants and shareholders; and
- remuneration incentivises the best possible outcomes for the broader stakeholder community, including fostering best practice in preventing bribery and/or corruption, along with driving sustainability and safety outcomes.

A. Executive Remuneration Framework for the Financial Year Ended 30 June 2023

The following table summarises the target remuneration mix for executives for the financial year ended 30 June 2023, based on maximum achievement of incentive plan outcomes:

Remuneration Mix – financial year ended 30 June 2023 (as a percentage of total remuneration, excluding Other Benefits)

1. "Other KMPs" includes the remuneration mix of the EVP and Chief Financial Officer and EVP and President Karoon Brazil.
2. The percentage of the CEO and Managing Director's at 'risk' STI and at 'risk' LTI is based on fixed remuneration at the conclusion of the financial year.

Set out below is a summary of the STI and LTI opportunity available to the CEO and Managing Director, Executive Vice President (EVP) and Chief Financial Officer (CFO) and EVP and President Karoon Brazil.

	CEO AND MANAGING DIRECTOR	EVP AND CHIEF FINANCIAL OFFICER	EVP AND PRESIDENT KAROON BRAZIL
STI OPPORTUNITY	75% of fixed remuneration[1]	87.5% of fixed remuneration[3]	87.5% of fixed remuneration[3]
LTI OPPORTUNITY	100% of fixed remuneration[2]	75% of fixed remuneration[4]	75% of fixed remuneration[4]

1. CEO/MD base STI opportunity increased to 100% on and from 1 January 2023, see ASX release dated 8 March 2023 and 'fixed remuneration' below. Prior to that, the base STI opportunity for the balance of FY23 was 50%. The aggregate at risk opportunity is illustrated above.
2. Participation in the LTI opportunity has been prorated from 1 January 2023, at the CEO/MDs revised fixed remuneration. The issuance of additional performance rights reflecting the increased LTI opportunity will be subject to shareholder approval at the 2023 Annual General Meeting.
3. Base STI opportunity for each of the EVP and CFO and EVP and President Karoon Brazil increased to 100% on and from 1 January 2023. Prior to that the base STI opportunity for the balance of FY23 was 75%. The aggregate at risk opportunity is illustrated above.
4. Participation for each of the EVP and CFO and EVP and President Karoon Brazil in the LTI opportunity has been prorated from 1 January 2023 based on the revised fixed remuneration for each KMP.

See pages 52–55 for additional information on the STI and LTI plans.

Fixed Remuneration

WHAT IS FIXED REMUNERATION?	Executives are entitled to fixed cash remuneration consisting of base salary and superannuation contributions/pension contributions. Fixed remuneration is not based on performance. Fixed remuneration excludes any accruals of annual or long service leave. Other benefits not included in fixed remuneration include any salary sacrifice items or non-monetary benefits including health insurance, motor vehicles, expatriate travel, certain membership and associated fringe benefits tax, depending on each individual's respective employment arrangements ('Other Benefits'). Details of other benefits paid to executives are set out in full on page 60.
HOW IS FIXED REMUNERATION REVIEWED?	Fixed remuneration is reviewed by the Board assisted by the People and Culture Committee. Broadly, fixed remuneration is positioned within a range that references the median of the relevant market for each role.
FIXED REMUNERATION FOR FY2023	Fixed remuneration of the executive KMP's increased during the year ended 30 June 2023, following a review by the Board and the People and Culture Committee in January 2023. The review was supported by an independent third-party expert who provided guidance on current trends in executive remuneration practices and undertook a detailed benchmarking review against a peer group of Australian and international companies. The fixed remuneration of KMP is set out in the table on page 60.

Superannuation

The Chief Executive Officer and Managing Director receives fixed remuneration inclusive of superannuation contributions, above the maximum contributions cap. Other Australian executives of the Company received statutory superannuation contributions of 10.5% of salary up to the maximum statutory contribution. Individuals may choose to sacrifice part of their salary to increase payments towards superannuation.

Social Security and Indemnity Fund Contributions

Karoon's Brazilian based executives are subject to specific Brazilian employment regulations, whereby the Group is required to contribute 27.3% of salary to the Government's social security fund. These contributions are subject to a cap on an annual, calendar year basis. However, the executives on retirement will only be entitled to a portion of the contributions made. A further 8% of executives salary is required to be contributed to a Federal Severance Indemnity Fund ('FGTS'). In the situation of unfair dismissal without just cause, the Group would have to pay a fine equivalent to 50% of the accumulated balance of the individual's FGTS account.

In addition to the above, the Group pays an amount equal to 10% of the monthly salary paid to the EVP and President Karoon Brazil into a private pension fund for the benefit of the EVP and President Karoon Brazil.

'At Risk' Remuneration

Karoon aims to align the interests of executives with those of shareholders by having a significant proportion of executive remuneration 'At Risk'. 'At Risk' remuneration represents the proportion of remuneration that requires pre-determined performance conditions to be met before the remuneration is vested to the executive. At the beginning of each financial year, the Board reviews the financial and operational goals and targets, looking broadly at where the building blocks for long-term value exist, then sets performance conditions that generate a link between operating performance, remuneration received and the value created for shareholders.

All executives that received grants of performance rights during the financial year ended 30 June 2023 received performance rights that were issued under the 2022 Performance Rights Plan ('2022 PRP').

STI Plan

The key features of the STI plan for the financial year ended 30 June 2023 ('FY2023 award') remain unchanged and are outlined in the table below:

WHO PARTICIPATES	All executives. Participation in the STI Plan is at the discretion of the Board of Directors on the recommendation of the People and Culture Committee.
WHAT IS THE CYCLE?	The annual performance cycle is 1 year – 1 July to 30 June. The Corporate Scorecard and role specific objectives are set by the Board initially to reflect key priorities to build long term value. Details of the FY2023 award Corporate Scorecard are set out on page 56.
WHAT IS THE LEVEL OF THE STI OPPORTUNITY?	The STI opportunity level of each executive is a pre-determined proportion of an executives' fixed remuneration. In respect of the FY2023 award, the CEO/MD can earn up to 75% of their fixed remuneration. The EVP and CFO and EVP and President Karoon Brazil can each earn up to 87.5% of their fixed remuneration. Senior leaders outside of the KMP participate at 70% of their fixed remuneration. The calculation of the FY2023 Award can be illustrated as follows: [Fixed Rem (at 1 July)[1] X STI Opportunity Level %] X Outcome of performance conditions[2] (as at 30 June) = STI award (for FY) 1. Please note that the Fixed Remuneration of the executives was subject to change during FY23, including the level of STI opportunity. See page 51. 2. Please note that for executives, excluding the CEO/MD, the outcome is a combination of the 'Corporate Scorecard' and individual role objectives, which is determined by the Board.

FORM OF INCENTIVE, IF AWARDED	Subject to the achievement of the performance conditions, the FY2023 award is delivered to senior executives in two parts, a cash element (50%) and a deferred element, represented by an offer and subsequent grant of performance rights (50%). The cash component of the FY2023 STI opportunity is paid following the achievement of applicable performance conditions. The quantum of performance rights to be granted is to be determined by dividing 50% of the total STI award (determined to be available based on the satisfaction of applicable corporate performance and (if appropriate) role specific objectives) for each employee by Karoon's weighted average share price in the 20-trading day period after the date of the release of the Company's 2023 full year financial results. Any performance rights granted will remain 'At Risk' until the satisfaction of retention conditions, which expire on 1 July 2024. Performance rights do not have a strike price. Each performance right provides the participant with the right to receive one fully paid ordinary share in Karoon, or its equivalent value, for no consideration. Under the rules of the 2022 PRP, ordinary shares issued or provided as a result of the exercise of vested and converted performance rights may be issued as new ordinary shares or ordinary shares acquired on market.
PERFORMANCE PERIOD	1 year.
DEFERRAL PERIOD	Performance rights granted in respect of the FY2023 award are subject to a retention period of 12 months, being the continuation of employment, immediately following the satisfaction of performance conditions, at the conclusion of the performance period.
WHAT ARE THE PERFORMANCE CONDITIONS?	As part of the 2023 remuneration review, for the financial year ended 30 June 2023 the Board set out the FY2023 award for short-term incentives based on a mix of the following performance hurdles:

	COMPANY-WIDE OBJECTIVES	ROLE-SPECIFIC OBJECTIVES
CEO and Managing Director	100%	Nil%
Other KMP	80%	20%

Company-wide Objectives

Company-wide Objectives were set by the Board at the beginning of the performance period.

The Company-wide Objectives, known as the 'Corporate Scorecard', includes financial and operational objectives, project objectives and strategic targets.

Role-specific Objectives

Role-specific Objectives were set at the beginning of the performance period and related directly to individual/team specific responsibilities.

All short-term performance outcomes are tempered by both a gateway for safety outcomes and a clawback (negative discretion) provision in relation to any fatality and bribery and/or corruption issues.

Further details on the performance conditions, targets and outcomes for the FY2023 award are outlined below in the STI outcomes within Section 3B on page 56.

GRANT DATE	In respect of performance rights, the grant date occurs following the offer and acceptance of performance rights. However, any performance rights offered and accepted by the Chief Executive Officer and Managing Director are subject to shareholder approval at the next Annual General Meeting prior to issuance.
WHAT HAPPENS AT THE END OF EMPLOYMENT?	Unvested performance rights will lapse on cessation of employment with Karoon, subject to the nature and circumstances of the termination and the discretion of the Board of Directors.
IF THERE IS A CHANGE OF CONTROL?	On a change of control, the Board of Directors may determine that a portion of the individual's unvested performance rights will vest based on pro-rata achievement of the performance conditions. Adjustments to an individual's unvested performance right may also occur in the event of a Company reconstruction and certain share issuances.
HOW DO STI'S LINK TO KAROON'S OBJECTIVES?	The STI framework is based on a set of challenging Company building goals, granted on a rolling short-term basis. Linking outcomes to operational performance develops an essential alignment between Karoon's year-to-year inherent value growth and rewards those who establish that value only when the company objectives are met. The Board assesses the objectives for the performance period annually in light of the long-term strategic building blocks and upcoming key value drivers within Karoon's operations, allowing for transparent measurement of company performance against these objectives. The Board recognises the risks associated with offshore oil production and drilling and considers ensuring the safety of the workforce, and avoiding any instances of bribery and corruption as paramount to its operations. Achieving appropriate safety standards is used as a gateway for any vesting of the STI, while any fatality or instance of bribery and corruption can be utilised to claw back incentives should they have been previously paid.

LTI Plan

The key features of the LTI grant for the financial year ended 30 June 2023 are outlined in the table below:

WHO PARTICIPATES

All executives.

Participation in the LTI plan is at the discretion of the Board of Directors on the recommendation of the People and Culture Committee. The LTI is a relative total performance measure over several years to align employees to Karoon's long term performance compared to others.

Performance rights granted will not vest and have no value to the executives unless the performance conditions are achieved.

LTI OPPORTUNITY

The LTI opportunity available to an executive is determined as a percentage of the executive's fixed remuneration. In respect of the FY23 LTI grant, the CEO/MD can earn up to 100% of their fixed remuneration. The EVP CFO and EVP President Karoon Brazil can each earn up to 75% of their fixed remuneration.

FORM OF INCENTIVE

The quantum of performance rights received was determined by dividing the LTI opportunity for each executive by the value weighted average price of Karoon Energy ordinary shares for the 20 trading days post 25 August 2022 (being the date on which Karoon's 2022 full year financial results were released to the market).

Performance rights do not have a strike price. Each performance right provides the participant with the right to receive one fully paid ordinary share in Karoon, or its equivalent value, for no consideration.

Under the rules of the 2022 PRP, ordinary shares issued or provided as a result of the exercise of vested and converted performance rights may be issued as new ordinary shares or ordinary shares acquired on-market.

PERFORMANCE PERIOD

3 years.

PERFORMANCE CONDITIONS

The LTI performance hurdles for the period commencing 1 July 2022 and ending 30 June 2025 are split 50% relative to TSR performance as assessed against a list of closely comparable and representative industry peer group companies, whose business models and/or regions of operations are similar to those of Karoon (Industry Peer Group); and 50% Absolute TSR (based on compound annual growth rate (CAGR)), which is set at a range of 10% to 18%.

INDUSTRY PEER GROUP

AUSTRALIAN MARKET PEERS

- Australis Oil & Gas Limited
- Beach Energy Limited
- Carnarvon Petroleum Limited
- Horizon Oil Limited
- Santos Limited
- Woodside Petroleum Limited
- Strike Energy Limited
- Central Petroleum Limited
- Cooper Energy Limited

GLOBAL PEERS

- Cairn Energy plc
- GeoPark Limited
- Gran Tierra Energy Inc
- Kosmos Energy Ltd
- New Zealand Oil & Gas Ltd
- Enauta Participações S.A.
- Pharos Energy plc
- Tullow Oil plc
- Petro Rio
- Jadestone Energy Inc

Vesting consideration details for the industry peer group companies is outlined below:

PERFORMANCE AGAINST INDUSTRY PEER GROUP	PROPORTION OF PERFORMANCE RIGHTS VESTING
Less than 50th percentile	Nil%
At 50th percentile	50%
Between 50th and 75th percentile	50% plus 2% for each additional percentile ranking above the 50th percentile
At or above 75th percentile	100%
At 100% percentile	100%

Vesting consideration details for the Absolute TSR measure are set out below:

ABSOLUTE TSR (CAGR)	PROPORTION OF PERFORMANCE RIGHTS VESTING
Less than 10%	Nil%
At 10%	50%
Between 10.01% and 17.99%	50% plus 6.25% for each additional percentage point above the 10% threshold
At or above 18.00%	100%

Companies that are no longer part of the Industry Peer Group at the end of the performance period (for instance, due to acquisition or delisting) may be removed from the Peer Group calculation.

GRANT DATE	Grant date occurs following the offer and acceptance of performance rights. However, any performance rights offered and accepted by the Chief Executive Officer and Managing Director are subject to shareholder approval at the next Annual General Meeting prior to issue.
EXERCISE PERIOD	Performance rights will remain exercisable for a period of one year following vesting.
WHAT HAPPENS AT THE END OF EMPLOYMENT?	Unvested (and unconverted) performance rights will lapse on cessation of employment with Karoon, subject to the nature and circumstances of the termination and the discretion of the Board of Directors.
IF THERE IS A CHANGE OF CONTROL	On a change of control, the Board of Directors may determine that a portion of the individual's unvested performance rights will vest, based on pro-rata achievement of the performance conditions. Adjustments to an individual's unvested performance right may also occur in the event of a Company reconstruction and certain share issuances.
LINK BETWEEN PERFORMANCE AND REWARD	The Board of Directors and People and Culture Committee considers it important to link remuneration to share price performance relative to Karoon's industry peer group companies and overall share price performance over the long-term. In the case where performance does not reach the 50th percentile, no incentive will be paid.

B. Executive Remuneration Outcomes

Relationship between the Executive Remuneration Framework and Company Performance

Karoon has a transparent performance-based remuneration structure in place that provides a direct link between Company performance and remuneration in the short and long-term. As part of this structure, executive rewards are directly linked to operational, safety and financial performance metrics along with relative market and absolute performance. 'At Risk' remuneration is only awarded if pre-determined Company building milestones are achieved or the Company outperforms an industry peer group of companies or achieves a minimum level of absolute return in the long term.

The tables below set out summary information about the Company's earnings, net assets and movements in shareholder wealth from 1 July 2018 to 30 June 2023.

FINANCIAL YEAR ENDED	30 JUNE 2023	30 JUNE 2022	30 JUNE 2021	30 JUNE 2020	30 JUNE 2019[A]
	US$M	US$M	US$M	US$M	US$M
Revenue	**566.5**	385.1	170.8	–	–
Profit/(loss) before income tax	**216.2**	(89.8)	(27.9)	(86.8)	(11.4)
Profit/(loss) for financial year	**163.0**	(64.4)	4.4	(86.2)	(13.3)
Net assets at end of financial year	**473.6**	276.2	380.3	359.5	298.8

FINANCIAL YEAR ENDED	30 JUNE 2023	30 JUNE 2022	30 JUNE 2021	30 JUNE 2020	30 JUNE 2019[A]
Share price at beginning of financial year	**A$1.74**	A$1.33	A$0.61	A$0.96	A$1.13
Share price at end of financial year	**A$1.97**	A$1.74	A$1.33	A$0.61	A$0.96
Basic earnings per ordinary share (US$)	**0.2899**	(0.1159)	0.0079	(0.1936)	(0.0550)
Diluted earnings per ordinary share (US$)	**0.2859**	(0.1159)	0.0077	(0.1936)	(0.0550)

A. The comparative financial information for the financial year ended 30 June 2019 has been restated for the voluntary change in presentation currency from A$ to US$ at the prevailing average exchange rates for the profit or loss and year-end rate for the balance sheet for each respective year.

Performance Hurdles and STI Outcomes for the Financial Year Ended 30 June 2023

The table below outlines the Company-wide Objectives, known as the Corporate Scorecard, for the financial year ended 30 June 2023:

MEASURE, RATIONALE AND PERFORMANCE	WEIGHT	TARGETS AND OUTCOMES				RESULT (% MAX)	CONTRI-BUTION
		THRESHOLD	TARGET	STRETCH	OUTCOME		
FINANCIAL AND OPERATIONAL OBJECTIVES							
Oil Production (kbbl)	17.5%	7,000	8,100	8,910	7,037	2.0%	0.4%
Group operating expenses[1] (US$m)	5.0%	180.0	150.2	135.2	134.9	100.0%	5.0%
Other controllable corporate costs[2] (US$m)	7.5%	23.8	22.6	21.4	20.9	100.0%	7.5%
Baúna Capex (US$m)	5.0%	9.4	8.6	7.8	3.3	100.0%	5.0%
Achieve Baúna intervention & Patola development capex targets[3] (US$m)	14.0%	> 325		<325	301	100.0%	14.0%
Baúna intervention production (bopd) Achieve the target production rate over 30 continuous days	3.0%	–		>20,000	>20,000	100.0%	3.0%
Patola production (bopd) Achieve the target production rate over 30 continuous days	3.0%	–		>30,000	–	0.0%	0.0%
Neon drilling (US$m)[4] Neon-1 and Neon-2 Capex. Target values exclude contingencies This target was also subject to achieving minimum resource estimates.	10.0%	64.7		54.4	48.0	100.0%	10.0%
Neon evaluation studies result in an increase in resource estimated[5] (MMbbl)	4.0%	1C min econ.	50	60	60.1	100.0%	4.0%
Neon Drilling & Evaluation Complete Neon evaluation study as well as analysis of Neon well results and updated field development plan	1.0%	Complete			Completed	100.0%	1.0%
STRATEGIC OBJECTIVES							
Growth Acquire a substantial second production asset	15.0%	Asset			No	0.0%	0.0%
ESG Limit group-wide voluntary staff turnover to a level below FY22 (% of total 30 June workforce)	2.5%	–			–	0.0%	0.0%
ESG: Identify additional carbon reduction project in operations[6]	2.5%	–			No	0.0%	0.0%
ESG: advance carbon sequestration project[7]	10.0%	1 Project			1 Project Achieved	100.0%	10.0%
Overall Corporate Performance Outcome	100.0%	0		100	60		60%*

1. Adjusted to exclude contingencies and adjust for fuel price inflation/deflation during FY23.
2. Defined as 'corporate other costs' in monthly accounts adjusted for Board approved additional costs (e.g. D&O insurance & change to budget assumptions with regard to time writing on acquisitions).
3. Capex spend adjusted for fuel price inflation/deflation during FY23.
4. This target was also subject to achieving minimum resource estimates.
5. A third party supports Contingent Resource estimates.
6. Identify and screen potential short term and long term emission reduction projects.
7. Identify, screen and enter at least one carbon sequestration project in Brazil or elsewhere to: a) achieve carbon neutrality by offsetting our remaining current CO_2e footprint; and b) to provide options to the Company for further CO_2e mitigation.

* Total may not add up due to rounding to zero decimal places.

Based on actual results, in respect of the:

- Current Chief Executive Officer and Managing Director, a total of 60% of the available STI opportunity, payable 50% in cash and 50% via a grant of performance rights (with such performance rights subject to a one year employment retention), satisfied the requisite STI performance targets outlined above.
- Other KMP, between 58% and 65% of the available STI opportunity satisfied requisite performance targets (based on the results of role-specific performance targets).

Performance rights (associated with the FY2023 STI award) once granted will have a 1-year retention period ending 30 June 2024 before they become exercisable and convertible into fully paid ordinary shares. The 2023 STI performance rights expire on 30 June 2025.

LTI Outcomes

Karoon's 2021 LTI performance conditions of achieving an absolute total shareholder return ('TSR') of 18% per annum and a minimum 50th percentile against the Company's Relative TSR when compared with a select group of peer companies over the period from 1 July 2020 to 30 June 2023 was met. Karoon was at the 80th percentile when compared against the relevant industry peer group and, accordingly, 100% of the 2021 LTI entitlement vested.

Voluntary Information: 2023 'Remuneration Received' (Non-IFRS Information)

The amounts disclosed below reflect the actual benefits received by each executive during the financial year ended 30 June 2023 and have been translated into US$ from local currencies using the average exchange rate for the 2023 financial year. The average rate used for A$/US$ was 0.6735 and R$/US$ was 0.1937. The amounts disclosed below include the actual value of any equity-settled and/or cash-settled award received from STI and/or LTI.

The amounts disclosed in the table below are not the same as the statutory remuneration expensed in relation to each executive in accordance with Australian Accounting Standards shown in the statutory table in Section 5 of the Remuneration Report. The remuneration values disclosed below have been determined as follows:

Short-term Incentives

Includes cash bonuses and the equity-settled and/or cash-settled award received from STI by executives, subject to achievement of performance conditions. The value of STI equity-settled and cash-settled awards received reflects the amounts disclosed to the relevant tax authorities during the financial year ended 30 June 2023.

Long-term Incentives

Includes the equity-settled award received from LTI by executives. The value of LTI equity-settled awards received reflects the amounts disclosed to the relevant tax authorities during the financial year ended 30 June 2023.

	FIXED REMUNERATION	SHORT-TERM INCENTIVES	LONG-TERM INCENTIVES	TOTAL REMUNERATION RECEIVED
	US$	US$	US$	US$
Executive Directors				
Dr Julian Fowles	622,149	178,489	–	800,638
Other KMP (Group)			–	
Mr Ray Church	499,102	105,823	–	604,925
Mr Antonio Guimarães	476,374	75,983	–	552,357

The Board of Directors believes that 'remuneration received' is relevant to shareholders for the following reasons:

- the statutory remuneration expensed through as share-based payments (Performance rights) is based on fair value at grant date and does not reflect the value of equity-settled and/or cash-settled amounts when they are actually received;
- the statutory remuneration shows benefits before they are actually received by executives;
- where performance rights do not vest because a market-based performance condition is not satisfied (for example, an increase in Karoon's share price), Karoon must still recognise the full amount of the share-based payments expense even though the executives do not receive the benefit; and

- share-based payment awards are treated differently under Australian Accounting Standards depending on whether the performance conditions are market conditions (no reversal of share-based payments expense) or non-market conditions (reversal of share-based payments expense when performance rights fail to vest), even though the benefit received by the executive is the same ($Nil where the performance right fail to vest).

C. Executive Agreements

Remuneration and other terms of employment for the executives are formalised in employment agreements. Each of these agreements provide for participation, when eligible, in the Company's PRP. Other major provisions of the agreements relating to remuneration are set out below.

Termination payments for executives, if any, are agreed by the Board and/or People and Culture Committee in advance of employment and stated in the relevant employment agreements. On retirement, executives are paid employee benefit entitlements accrued to the date of retirement.

Details of existing employment agreements between the Company and the Executive Director and other KMP are as follows:

NAME	TERM	EXPIRY	NOTICE/TERMINATION PERIOD	TERMINATION PAYMENTS	PERFORMANCE RIGHT ELIGIBLE
Executive Directors					
Dr Julian Fowles	From 27 November 2020, ongoing	Ongoing	In writing six months	Not applicable.	Yes
Other KMP					
Mr Ray Church	From 27 September 2021, ongoing	Ongoing	In writing six months	Not applicable.	Yes
Mr Antonio Guimarães	From 1 October 2021, ongoing	Ongoing	In accordance with Brazilian labour legislation	Not applicable (statutory entitlements).	Yes

All termination payments for Australian employees are subject to the limits prescribed under Section 200B of the *Corporations Act 2001*.

The employment agreements of executives are on a continuing basis, the terms of which are not expected to change in the immediate future.

Section 4. Independent Non-Executive Chair and Non-Executive Directors

Fees and payments to the independent Non-Executive Chair and other Non-Executive Directors reflect the demands which are placed on, and the responsibilities of the Directors of Karoon. The Company reviews Independent Non-Executive Chair and other Non-Executive Director remuneration annually and assesses the change to the Company's activities and overall responsibilities of each Non-Executive Director.

Following a review in July 2022, it was resolved to increase the fees paid to Non-Executive Directors' as follows:

- a 5% fee increase be applied to the base fee of the non-executive chair, increasing the fee by A$11,000 to A$231,000;
- a 5% fee increase be applied to the base fee of the non-executive directors, increasing the fee by A$5,000 to A$105,000;
- a A$5,000 increase be applied to the committee fees payable to the chair of each Board committee, taking the fee from A$25,000 to A$30,000; and
- a 5% increase be applied to committee member fees, increasing the fees payable:
  - to members of the Audit, Risk and Governance Committee by A$1,000 to A$21,000.
  - to members of the People and Culture Committee and the Sustainability and Operational Risk Committee by A$750 to A$15,750.

The fee increases approved were based on market comparators, the length of time since the last fee increase, the existing fee pool limit and the potential impact on future director recruitment.

The table at the end of this section provides a summary of Karoon's Non-Executive Director fee schedule for the 2023 financial year.

Superannuation contributions are paid, in accordance with Australian superannuation guarantee legislation, on Directors' fees paid to Australian resident Non-Executive Directors. An increase in fees consistent with the statutory increase in superannuation contributions of 0.5% was paid to Australian resident Non-Executive Directors from 1 July 2022.

Non-Executive Director fees are determined within an aggregate Directors' fee pool limit, which is periodically approved by shareholders. The maximum aggregate amount, including superannuation contributions, that may be paid to Non-Executive Directors of the Company as remuneration for their services per annum is A$1,200,000, as approved by shareholders at the Company's 2015 Annual General Meeting. For the financial year ended 30 June 2023, the total fees paid to Non-Executive Directors was A$995,336.

Share-based Remuneration

Non-Executive Directors do not receive performance-related remuneration. The Company has determined that it will not grant bonus or incentive related share-based remuneration to Non-Executive Directors. Non-Executive Directors will continue to be encouraged to purchase ordinary shares in the Company on-market in accordance with the Director Minimum Shareholding Policy.

Retirement Allowance for Directors

Karoon does not provide any Non-Executive Director with a retirement allowance.

Non-Executive Director Fees for the Financial Year Ended 30 June 2023

Non-Executive Directors' fees for the financial year ended 30 June 2023 (excluding superannuation contribution) are outlined in the following table:

	FY2023	FY2022
Base fee		
Non-Executive Chairman*	**A$231,000**	A$220,000
Non-Executive Directors	**A$105,000**	A$100,000
Committee member fees		
Audit, Risk and Governance Committee		
Chair	**A$30,000**	A$25,000
Member	**A$21,000**	A$20,000
People and Culture Committee		
Chair	**A$25,000**	A$20,000
Member	**A$15,750**	A$15,000
Sustainability and Operational Risk Committee		
Chair	**A$25,000**	A$20,000
Member	**A$15,750**	A$15,000

* Non-Executive Chairman base fee includes compensation for the appointment to relevant Committees.

Section 5. Statutory and Share-based Reporting

Details of the Remuneration of the Directors and Other Key Management Personnel

Details of the remuneration of the Directors and other KMP of the Group for the financial year and previous financial year are set out in the following tables. For all remuneration reporting stated in US$, exchange rates of AU$/US$ 0.6735 (2022: 0.7259) and R$/US$ 0.1937 (2022: 0.1909) have been used.

Financial Year Ended 30 June 2023

	Short-term Benefits			Post-employment Benefits		Leave Benefits*	Share-based Payments Expense		
NAME	CASH SALARY AND FEES US$	OTHER US$	CASH STI/BONUS US$	SUPER-ANNUATION/ PENSION CONTRIBUTIONS US$	SOCIAL SECURITY & INDEMNITY FUND CONTRIBUTIONS US$	LEAVE ENTITLEMENTS US$	PERFORMANCE RIGHTS US$	PERFORMANCE BASED REMUNERATION** %	TOTAL REMUNERATION US$
Executive Directors									
Dr Julian Fowles	**568,173**	**–**	**141,309**	**53,976**	**–**	**42,387**	**694,983**	**55.7**	**1,500,828**
Non-Executive Directors									
Mr Bruce Phillips	**155,578**	**–**	**–**	**16,336**	**–**	**–**	**–**	**–**	**171,914**
Ms Luciana Rachid	**87,555**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**87,555**
Mr Clark Davey	**101,530**	**–**	**–**	**10,661**	**–**	**–**	**–**	**–**	**112,191**
Mr Peter Turnbull	**112,306**	**–**	**–**	**11,792**	**–**	**–**	**–**	**–**	**124,098**
Mr Peter Botten	**95,469**	**–**	**–**	**10,024**	**–**	**–**	**–**	**–**	**105,493**
Mr Tadeu Fraga	**69,108**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**69,108**
Total Directors' remuneration	**1,189,719**	**–**	**141,309**	**102,789**	**–**	**42,387**	**694,983**		**2,171,187**
Other KMP (Group)									
Mr Ray Church	**441,485**	**40,582**	**131,609**	**17,034**	**–**	**30,160**	**299,529**	**44.9**	**960,399**
Mr Antonio Guimarães	**323,390**	**75,920**	**86,914**	**28,153**	**48,911**	**6,601**	**198,603**	**37.2**	**768,492**
Total other KMP remuneration (Group)	**764,875**	**116,502**	**218,523**	**45,187**	**48,911**	**36,761**	**498,132**		**1,728,291**
Total KMP remuneration (Group)	**1,954,594**	**116,502**	**359,832**	**147,976**	**48,911**	**79,148**	**1,193,115**		**3,900,078**

* Leave benefits include annual leave and long service leave entitlements. The prior financial year included long service leave entitlements only.

** The percentage of total remuneration consisting of performance rights, based on the value of performance rights expensed in the consolidated statement of profit or loss and other comprehensive income during the financial year.

Financial Year Ended 30 June 2022

NAME	Short-term Benefits CASH SALARY AND FEES US$	OTHER US$	CASH STI/BONUS US$	Post-employment Benefits SUPER-ANNUATION/ PENSION CONTRIBUTIONS US$	SOCIAL SECURITY & INDEMNITY FUND CONTRIBUTIONS US$	Long-term Benefits LONG SERVICE LEAVE US$	Share-based Payments Expense PERFORMANCE RIGHTS US$	PERFORMANCE BASED REMUNERATION %	TOTAL REMUNERATION US$
Executive Directors									
Dr Julian Fowles	561,302	–	156,176	53,324	–	3,253	513,533	52.0	1,287,588
Non-Executive Directors									
Mr Bruce Phillips	159,698	–	–	15,970	–	–	–	–	175,668
Ms Luciana Rachid	87,108	–	–	–	–	–	–	–	87,108
Mr Clark Davey	101,626	–	–	10,163	–	–	–	–	111,789
Mr Peter Turnbull	112,515	–	–	11,251	–	–	–	–	123,766
Mr Peter Botten	97,997	–	–	9,800	–	–	–	–	107,797
Total Directors' remuneration	**1,120,246**	**–**	**156,176**	**100,508**	**–**	**3,253**	**513,533**		**1,893,716**
Other KMP (Group)									
Mr Ray Church (commenced 27 September 2021)	327,493	29,590	193,164	14,257	–	508	162,454	38.9	727,466
Mr Antonio Guimarães (commenced 1 October 2021)	187,518	13,879	180,428	22,908	41,095	–	92,229	30.5	538,057
Total other KMP remuneration (Group)	**515,011**	**43,469**	**373,592**	**37,165**	**41,095**	**508**	**254,683**		**1,265,523**
Total KMP remuneration (Group)	**1,635,257**	**43,469**	**529,768**	**137,673**	**41,095**	**3,761**	**768,216**		**3,159,239**

* The percentage of total remuneration consisting of performance rights, based on the value of performance rights expensed in the consolidated statement of profit or loss and other comprehensive income during the financial year.

The amounts disclosed for the remuneration of Directors and other KMP include the assessed fair values of performance rights granted during the financial year, at the date they were granted, with the exception of performance rights for the FY2023 STI award, where the fair value is equivalent to the STI opportunity achieved based on a percentage of fixed remuneration. Performance rights for the FY2023 award will be granted following the release of the Company's 2023 full year results. The value attributable to performance rights is allocated to the relevant vesting period of the award in accordance with AASB 2 *'Share-based Payment'*, which requires the value of a performance right at grant date to be allocated equally over the vesting period, adjusted for not meeting the vesting condition. For performance rights that vest immediately, the value is disclosed as remuneration immediately, in accordance with the accounting policy described in Note 1(s) of the consolidated financial statements. In addition, acceleration of vesting occurs for performance rights up to the end of an employee's respective service period, where the rights are retained post cessation of employment.

With the exception of long-term performance rights granted during the current financial year, the fair value of performance rights was based on the Company's closing share price at grant date. Long-term performance rights granted during the current financial year, which are subject to market-based performance conditions, have been valued using a Monte Carlo simulation approach.

The relative percentage proportions of remuneration that are linked to performance conditions, those that are not and those that are fixed are as follows:

	Not Related to Performance Conditions				Related to Performance Conditions					
	Fixed Remuneration		Cash Bonus		Cash Bonus		STI (Performance Rights)		LTI (Performance Rights)	
NAME	2023	2022	2023	2022	2023	2022	2023	2022	2023	2022
Executive Director										
Dr Julian Fowles	**44.3%**	48.0%	**–**	–	**9.4%**	12.1%	**4.7%**	3.7%	**41.6%**	36.2%
Non-Executive Directors										
Mr Bruce Phillips	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Ms Luciana Rachid	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Mr Clark Davey	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Mr Peter Turnbull	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Mr Peter Botten	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Mr Tadeu Fraga	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–
Other KMP (Group)										
Mr Ray Church	**55.1%**	51.1%	**–**	10.0%	**13.7%**	16.6%	**6.8%**	8.3%	**24.4%**	14.0%
Mr Antonio Guimarães	**62.8%**	49.3%	**–**	20.2%	**11.3%**	13.3%	**5.6%**	6.7%	**20.3%**	10.5%

Further information on performance rights is set out in Note 29 of the consolidated financial statements.

Amounts disclosed for remuneration of Directors and other KMP exclude insurance premiums paid by the Company in respect of Directors' and officers' liability insurance contracts, as the contracts do not specify premiums paid in respect of individual Directors and officers. Information relating to insurance contracts is set out in this Directors' Report.

Share-based Remuneration

As at 30 June 2023, there were 9,063,068 performance rights issued under the 2019 PRP and 2022 PRP respectively, representing approximately 1.61% of the Company's total number of shares issued. Subsequent to year end, 2,883,931 performance rights have been exercised as outlined on page 45.

The terms and conditions of each grant of performance rights over unissued ordinary shares in the Company affecting remuneration in the current or a future financial year are as follows:

GRANT DATE	DATE VESTED AND EXERCISABLE	EXPIRY DATE	EXERCISE PRICE PER PERFORMANCE RIGHT	FAIR VALUE PER PERFORMANCE RIGHT AT GRANT DATE	% VESTED	PERFORMANCE CONDITION ACHIEVED
Performance rights						
25 September 2020	1 July 2023	30 June 2024	$–	A$0.587	100	2023 Performance Condition
27 November 2020	1 July 2023	30 June 2024	$–	A$1.572	100	2023 Performance Condition
23 March 2022	1 July 2024	30 June 2025	$–	A$1.815	–	To be determined
6 May 2022	1 July 2024	30 June 2025	$–	A$1.525	–	To be determined
24 November 2022	1 July 2025	30 June 2026	$–	A$1.707	–	To be determined
24 November 2022	1 July 2023	30 June 2024	$–	A$2.300	100	2022 Performance Condition
16 December 2022	1 July 2025	30 June 2026	$–	A$1.559	–	To be determined
16 December 2022	1 July 2023	30 June 2024	$–	A$2.160	100	2022 Performance Condition
31 March 2023	1 July 2025	30 June 2026	$–	A$1.508	–	To be determined
30 June 2023*	1 July 2025	30 June 2026	$–	A$1.332	–	To be determined

* Performance rights associated with the 2023 Long Term incentive that are subject to shareholder approval at the 2023 Annual General Meeting.

Performance rights are granted for no consideration. Performance rights granted carry no dividend or voting rights.

Number of Performance Rights Provided as Remuneration During the Financial Year

Details of performance rights over unissued ordinary shares in the Company provided as remuneration to each Director and each of the other KMP, including their personally related parties, are set out below:

NAME	NUMBER OF PERFORMANCE RIGHTS GRANTED DURING FINANCIAL YEAR	FAIR VALUE PER PERFORMANCE RIGHT AT GRANT DATE*	VALUE OF PERFORMANCE RIGHTS AT GRANT DATE*	NUMBER OF PERFORMANCE RIGHTS VESTED DURING FINANCIAL YEAR	NUMBER OF PERFORMANCE RIGHTS FORFEITED	VALUE OF PERFORMANCE RIGHTS FORFEITED
Executive Directors						
Dr Julian Fowles						
– Performance rights (LTI)	432,577	A$1.707	A$738,409	–	–	–
– Performance rights (LTI)**	12,649	A$1.332	A$16,848	–	–	–
– Performance rights (STI)	62,891	A$2.30	A$144,649	–	–	–
Other key management personnel (Group)						
Mr Ray Church						
– Performance rights (LTI)	230,014	A$1.559	A$358,592	–	–	–
– Performance rights (LTI)	16,083	A$1.508	A$24,253	–	–	–
– Performance rights (STI)	75,730	A$2.160	A$163,577	–	–	–
Mr Antonio Guimarães						
– Performance rights (LTI)	160,788	A$1.559	A$250,668	–	–	–
– Performance rights (LTI)	18,720	A$1.508	A$28,230	–	–	–
– Performance rights (STI)	51,251	A$2.160	A$110,702	–	–	–
Total key management personnel – Performance rights	**1,060,703**		**A$1,835,928**	**–**	**–**	**–**

* The value at grant date, calculated in accordance with AASB 2, of performance rights granted during the financial year as part of their remuneration.

** Performance rights associated with the 2023 Long Term incentive that are subject to shareholder approval at the 2023 Annual General Meeting.

No performance rights over unissued ordinary shares in the Company, held by any Director or other KMP, lapsed during the financial year.

Details of Remuneration – Performance Rights

For each grant of performance rights in the current or previous financial years which resulted in a share-based payment expense to Directors and other KMP, the percentage of the grant that vested and percentage that was forfeited because the individual did not meet the service and/or pre-determined performance conditions is set out below:

NAME	FINANCIAL YEAR END GRANTED	VESTED %	FORFEITED %	FINANCIAL YEARS IN WHICH SHARE OPTIONS OR PERFORMANCE RIGHTS MAY VEST	MAXIMUM TOTAL VALUE OF GRANT YET TO VEST US$
Executive Director					
Dr Julian Fowles					
– Performance rights (LTI)	30 June 2022	–	–	30 June 2025	198,089
– Performance rights (LTI)	30 June 2023	–	–	30 June 2026	339,631
– Performance rights (STI)*	30 June 2024	–	–	30 June 2025	70,826
Other KMP (Group)					
Mr Ray Church					
– Performance rights (LTI)	30 June 2022	–	–	30 June 2025	94,878
– Performance rights (LTI)	30 June 2023	–	–	30 June 2026	172,156
– Performance rights (STI)*	30 June 2024	–	–	30 June 2025	66,074
Mr Antonio Guimarães					
– Performance rights (LTI)	30 June 2022	–	–	30 June 2025	52,405
– Performance rights (LTI)	30 June 2023	–	–	30 June 2026	125,413
– Performance rights (STI)*	30 June 2024	–	–	30 June 2025	43,243

* Performance rights for the deferred portion of the FY2023 award will be granted following the release of the Company's 2023 full year results. The number of performance rights will depend on the Company's weighted average share price in the 20-trading day period after the release of the Company's 2023 full year financial results.

No performance rights will vest if the service and/or pre-determined performance conditions are not met, therefore the minimum value of the performance right yet to vest is $Nil.

The maximum value of performance rights yet to vest was determined as the amount of the grant date fair value of the performance rights that is yet to be expensed in the consolidated statement of profit or loss and other comprehensive income. For the FY2023 award, the maximum value yet to vest is equivalent to the STI opportunity achieved, based on a percentage of fixed remuneration, to be expensed over the remaining vesting period.

Performance Rights over Unissued Ordinary Shares in the Company as at 30 June 2023

During the financial year 1,060,703 performance rights over unissued ordinary shares in the Company were issued to Directors and other KMP, including their personally related parties.

The movement of performance rights over unissued ordinary shares in the Company held by Directors and other KMP, including their personally related parties, during the financial year was as follows:

	BALANCE AS AT 1 JULY 2022	GRANTED AS REMUNERATION	VESTED AND CONVERTED PERFORMANCE RIGHTS	PERFORMANCE RIGHTS FORFEITED	OTHER	BALANCE AS AT 30 JUNE 2023	TOTAL VESTED AND EXERCISABLE AS AT 30 JUNE 2023	TOTAL UNVESTED AS AT 30 JUNE 2023
Executive Director								
Dr Julian Fowles								
– Performance rights	1,080,041	508,117	–	–	–	1,588,158	–	1,588,158
Non-Executive Directors								
Mr Bruce Phillips								
Ms Luciana Rachid	–	–	–	–	–	–	–	–
Mr Clark Davey	–	–	–	–	–	–	–	–
Mr Peter Turnbull	–	–	–	–	–	–	–	–
Mr Peter Botten	–	–	–	–	–	–	–	–
Mr Tadeu Fraga	–	–	–	–	–	–	–	–
Other KMP								
Mr Ray Church								
– Performance rights	276,389	321,827	–	–	–	598,216	–	598,216
Mr Antonio Guimarães								
– Performance rights	152,660	230,759	–	–	–	383,419	–	383,419
Total key management personnel – Performance rights	**1,509,090**	**1,060,703**	**–**	**–**	**–**	**2,569,793**	**–**	**2,569,793**

All performance rights granted during the financial year were issued under the 2022 PRP.

The number of ordinary shares held by Directors and other KMP, including their personally related parties, as at 30 June 2023 was as follows:

	BALANCE AS AT 1 JULY 2022	RECEIVED AS REMUNERATION	EXERCISED (SHARE OPTIONS)/VESTED AND CONVERTED (PERFORMANCE RIGHTS)	SHARES PURCHASED	ORDINARY SHARES SOLD	BALANCE AS AT 30 JUNE 2023
Executive Director						
Dr Julian Fowles	107,659	–	–	–	–	**107,659**
Non-Executive Directors						
Mr Bruce Phillips	1,750,000	–	–	–	–	**1,750,000**
Mr Clark Davey	147,214	–	–	–	–	**147,214**
Mr Peter Turnbull	146,269	–	–	26,731	–	**173,000**
Ms Luciana Rachid	52,960	–	–	–	–	**52,960**
Mr Peter Botten	–	–	–	–	–	**–**
Mr Tadeu Fraga	–	–	–	–	–	**–**
Other KMP						
Mr Ray Church	–	–	–	–	–	**–**
Mr Antonio Guimarães	–	–	–	–	–	**–**
Total KMP	**2,204,102**	**–**	**–**	**26,731**	**–**	**2,230,833**

None of the ordinary shares are held nominally by any Director or any of the other key management personnel. 'Held nominally' refers to the situation where the ordinary shares are in the name of the Director or other key management person, but they are not the beneficial owner.

Other Transactions with Directors and Other KMP

A formal Related Party Protocol requires the approval by the People and Culture Committee and, thereafter, the Board of Directors of all new related party transactions.

During the financial year, Mr Tadeu Fraga, a Non-Executive Director, had an interest in Radix Engenharia e Software (Radix), that provided engineering consulting services to the Group at market prices. The contract value for these services from Mr Fraga's appointment on 26 August 2022 to 30 June 2023 was US$171,190. Mr Fraga's interest in Radix commenced on 1 March 2023, post the execution of the contract.

During the financial year, Ms Carolina Fraga, a family member of Mr Tadeu Fraga, a Non-Executive Director, who was appointed on 26 August 2022, remained employed by the Group as HR Co-ordinator in Brazil. The total value of her remuneration (including share-based payments expense) from 26 August 2022 to 30 June 2023 was US$89,841. Ms Fraga has been an employee of the Group since 2021. Ms Fraga's employment with the Karoon group commenced prior to the appointment of the relevant Non-Executive Director.

Loans to Directors and Other KMP

There were no loans to Directors or other KMP during the financial year.

Rounding

The amounts in the financial report are rounded to the nearest hundred thousand dollars unless otherwise indicated, under the option available to the Company under ASIC Corporations (Rounding in Financial/Directors Reports) Instrument 2016/191. The Company is an entity to which this legislative instrument applies.

This Directors' Report, incorporating the Remuneration Report, is made in accordance with a resolution of the Directors.

On behalf of the Directors:

Mr Bruce Phillips
Independent Non-Executive Chairman

Dr Julian Fowles
Chief Executive Officer and Managing Director

23 August 2023

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Auditor's Independence Declaration

As lead auditor for the audit of Karoon Energy Ltd for the year ended 30 June 2023, I declare that to the best of my knowledge and belief, there have been:

(a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and

(b) no contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Karoon Energy Ltd and the entities it controlled during the period.

Graeme McKenna

Graeme McKenna
Partner
PricewaterhouseCoopers

Melbourne
23 August 2023

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CONSOLIDATED FINANCIAL STATEMENTS

FOR THE FINANCIAL YEAR ENDED 30 JUNE 2023

Karoon Energy Ltd (the 'Company') is a public company limited by shares and is listed on the ASX. It is incorporated and domiciled in Australia.

The registered office and principal place of business of Karoon Energy Ltd is Suite 3.02, Level 3, 6 Riverside Quay, Southbank VIC 3006.

The consolidated financial statements are for the consolidated entity consisting of the Company and its subsidiaries.

The consolidated financial statements are presented in United States dollars.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

For the Financial Year Ended 30 June 2023

	NOTE	CONSOLIDATED 2023 US$M	2022 US$M
Revenue	4(a)	**566.5**	385.1
Cost of Sales	5(a)	**(283.2)**	(191.7)
Gross Profit		**283.3**	193.4
Other income	4(b)	**5.7**	0.8
Business development and transition costs	5(b)	**(3.7)**	(3.4)
Exploration expenses	5(c)	**(3.9)**	(3.2)
Finance costs	5(d)	**(25.4)**	(22.7)
Net foreign currency gains/(losses)		**(0.8)**	6.2
Other expenses	5(e)	**(33.8)**	(33.8)
Change in fair value of contingent consideration	22(ii)	**(5.2)**	(227.1)
Profit/(Loss) before income tax		**216.2**	(89.8)
Income tax (expense)/benefit	6	**(53.2)**	25.4
Profit/(Loss) for financial year attributable to equity holders of the Company		**163.0**	(64.4)
Other comprehensive income, net of income tax:			
Items that may be reclassified subsequently to profit or loss			
Exchange differences arising from the translation of financial statements into presentation currency		**(1.5)**	(4.3)
Net change in fair value of cash flow hedges and cost of hedging	23	**33.3**	(41.3)
Other comprehensive income/(loss) for financial year, net of income tax		**31.8**	(45.6)
Total comprehensive income/(loss) for financial year attributable to equity holders of the Company, net of income tax		**194.8**	(110.0)
Earnings per share attributable to equity holders of the Company:			
Basic earnings per ordinary share (cents per share)	9	**28.99**	(11.59)
Diluted earnings per ordinary share (cents per share)	9	**28.59**	(11.59)

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at 30 June 2023

	NOTE	CONSOLIDATED 2023 US$M	CONSOLIDATED 2022 US$M
Current assets			
Cash and cash equivalents	10	**74.8**	157.7
Receivables	11	**71.1**	56.4
Inventories	12	**8.7**	19.4
Security deposits	13	**0.4**	0.3
Other financial assets	22	**3.0**	–
Other assets	14	**9.2**	11.8
Total current assets		**167.2**	245.6
Non-current assets			
Deferred tax assets	6	**124.7**	123.0
Inventories	12	**8.3**	5.8
Oil and gas assets	15	**798.7**	733.0
Property, plant and equipment	16	**2.7**	13.3
Intangible assets		**0.1**	–
Exploration and evaluation assets	17	**85.7**	40.9
Security deposits	13	**2.3**	1.3
Other assets	14	**0.7**	1.3
Total non-current assets		**1,023.2**	918.6
Total assets		**1,190.4**	1,164.2
Current liabilities			
Trade and other payables	18	**57.2**	68.3
Current tax liabilities		**5.6**	9.6
Other financial liabilities	22	**86.0**	125.4
Lease liabilities	20	**47.2**	43.7
Provisions	19	**0.2**	0.4
Total current liabilities		**196.2**	247.4
Non-current liabilities			
Trade and other payables	18	**5.8**	6.8
Borrowings	21	**28.1**	27.1
Other financial liabilities	22	**133.0**	222.0
Lease liabilities	20	**200.4**	245.2
Provisions	19	**153.3**	139.5
Total non-current liabilities		**520.6**	640.6
Total liabilities		**716.8**	888.0
Net assets		**473.6**	276.2
Equity			
Contributed equity	23	**907.5**	907.5
Accumulated losses		**(315.8)**	(478.8)
Reserves		**(118.1)**	(152.5)
Total equity		**473.6**	276.2

The above consolidated statement of financial position should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the Financial Year Ended 30 June 2023

CONSOLIDATED	NOTE	CONTRIBUTED EQUITY US$M	ACCUMULATED LOSSES US$M	SHARE-BASED PAYMENTS RESERVE US$M	FOREIGN CURRENCY TRANSLATION RESERVE US$M	HEDGING RESERVES US$M	TOTAL EQUITY US$M
Balance as at 1 July 2021		905.1	(414.4)	50.2	(160.7)	–	380.2
Loss for financial year		–	(64.4)	–	–	–	(64.4)
Other comprehensive loss		–	–	–	(4.3)	(41.3)	(45.6)
Total comprehensive income/(loss) for financial year		–	(64.4)	–	(4.3)	(41.3)	(110.0)
Transactions with owners in their capacity as owners:							
Exercise of options	23(b)	2.4	–	–	–	–	2.4
Share-based payments expense	29(c)	–	–	3.6	–	–	3.6
Balance as at 30 June 2022		**907.5**	**(478.8)**	**53.8**	**(165.0)**	**(41.3)**	**276.2**
Profit for financial year		**–**	**163.0**	**–**	**–**	**–**	**163.0**
Other comprehensive income (loss)		**–**	**–**	**–**	**(1.5)**	**33.3**	**31.8**
Total comprehensive income/(loss) for financial year		**–**	**163.0**	**–**	**(1.5)**	**33.3**	**194.8**
Transactions with owners in their capacity as owners:							
Share-based payments expense	29(c)	**–**	**–**	**2.6**	**–**	**–**	**2.6**
		–	**–**	**2.6**	**–**	**–**	**2.6**
Balance as at 30 June 2023		**907.5**	**(315.8)**	**56.4**	**(166.5)**	**(8.0)**	**473.6**

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the Financial Year ended 30 June 2023

	NOTE	CONSOLIDATED 2023 US$M	CONSOLIDATED 2022 US$M
Cash flows from operating activities			
Receipts from customers		**552.9**	362.9
Payments to suppliers and employees		**(135.2)**	(116.5)
Payments for exploration and evaluation expenditure expensed		**(4.0)**	(3.5)
Payments for legal settlement		**–**	(9.6)
Payments for cash flow hedges		**(13.4)**	(20.8)
Interest received		**4.2**	–
Borrowing and other costs of finance paid		**(19.8)**	(18.9)
Income taxes paid		**(78.8)**	(39.4)
Net cash flows from operating activities	28(a)	**305.9**	154.2
Cash flows from investing activities			
Payments for plant and equipment and computer software		**(2.5)**	(5.1)
Acquisition of oil and gas assets		**(84.5)**	(43.6)
Payments for oil and gas assets		**(222.5)**	(59.6)
Borrowing costs paid for qualifying assets		**(2.7)**	(5.8)
Payments for exploration and evaluation expenditure capitalised		**(43.1)**	–
Payment for security deposits		**(0.9)**	(0.3)
Proceeds from disposal of non-current assets		**–**	1.4
Net cash flows used in investing activities		**(356.2)**	(113.0)
Cash flows from financing activities			
Principal elements of lease payments		**(34.1)**	(44.6)
Proceeds from issue of ordinary shares		**–**	2.4
Proceeds from borrowings		**–**	30.0
Debt facility costs		**(0.1)**	(3.3)
Net cash flows used in financing activities		**(34.2)**	(15.5)
Net increase/(decrease) in cash and cash equivalents		**(84.5)**	25.7
Cash and cash equivalents at beginning of financial year		**157.7**	133.3
Effect of exchange rate changes on cash and cash equivalents held in foreign currencies		**1.6**	(1.3)
Cash and cash equivalents at end of financial year	10	**74.8**	157.7

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements are for the consolidated entity consisting of the Company and its subsidiaries (the 'Group'). Information on the nature of the operations and principal activities of the Group are described in the Directors' Report.

The following is a summary of significant accounting policies adopted by the Group in the preparation of these consolidated financial statements. The accounting policies have been consistently applied to all the financial years presented, unless otherwise stated.

(a) Basis of Preparation

These general purpose financial statements have been prepared in accordance with Australian Accounting Standards and Interpretations issued by the Australian Accounting Standards Board (the 'AASB') and the *Corporations Act 2001* (Cth). The Company is a for-profit entity for the purpose of preparing financial statements.

The financial statements have been prepared on a going concern basis. For further details please refer to the liquidity risk section in Note 3(d).

Rounding

The amounts in the financial statements are rounded to the nearest hundred thousand dollars unless otherwise indicated, under the option available to the Company under ASIC Corporations (Rounding in Financial/Directors Reports) Instrument 2016/191. The Company is an entity to which this legislative instrument applies.

Historical Cost Convention

The consolidated financial statements have been prepared on an accrual basis under the historical cost convention as modified, when relevant, by the revaluation of selected financial assets and financial liabilities for which the fair value basis of accounting has been applied.

Significant Accounting Estimates, Assumptions and Judgements

The preparation of financial statements requires the use of certain significant accounting estimates. It also requires management to exercise its judgement in the process of applying Group accounting policies. The areas involving a high degree of judgement or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements are disclosed in Note 2.

Compliance with International Financial Reporting Standards

Compliance with Australian Accounting Standards ensures that the consolidated financial statements comply with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Climate Change

In preparing the financial statements, the impact of climate change and current climate-related legislation has been considered.

The impact of climate change is considered in the significant judgements in a number of areas in the financial statements not limited to:

- Impairment of oil and gas assets (refer Note 2(a)); and
- Provision for restoration (refer Note 2(c)).

The Group continues to monitor climate related policy and its impact on the financial statements.

New, Revised or Amended Australian Accounting Standards and Interpretations that are First Effective in the Current Reporting Period

The Group has adopted all of the new, revised and/or amended Australian Accounting Standards and Interpretations issued by the AASB that are relevant to its operations and effective for the financial year ended 30 June 2023:

New and revised Australian Accounting Standards and amendments thereof and Interpretations effective for the financial year include:

- *AASB 2020-3 Amendments to Australian Accounting Standards – Annual Improvements 2018-2020 and Other Amendments.*

The initial adoption of the amendments listed above has not resulted in any changes to the Group's accounting policies and has had no effect on either the amounts reported for the current or previous years.

New standards and interpretations not yet adopted

The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective. These standards, amendments or interpretations are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

(b) Basis of Consolidation

The consolidated financial statements incorporate the assets and liabilities of all subsidiaries of the Company as at 30 June 2023 and the results of all subsidiaries for the financial year then ended.

Subsidiaries are all entities (including special purpose entities) over which the Group has control. The Group controls an entity when the Group is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are deconsolidated from the date that control ceases.

Interests in subsidiaries are set out in Note 24.

All subsidiaries have a financial year end of 30 June, with the exception of: Karoon Petróleo & Gás Ltda; Karoon Peru Pty Ltd, Sucursal del Peru; and KEI (Peru Z38) Pty Ltd, Sucursal del Peru which have a financial year end of 31 December in accordance with relevant Brazilian and Peruvian tax and accounting regulations respectively.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES CONTINUED

Accounting policies of subsidiaries have been changed, where necessary, to ensure consistency with the policies applied by the Group.

Intercompany transactions, balances and unrealised gains on transactions between Group companies are eliminated on consolidation. Unrealised losses are also eliminated, unless the transaction provides evidence of the impairment of the asset transferred.

(c) Segment Information

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for assessing performance and in determining the allocation of resources of the operating segments, has been identified as the Group's Executive Management Team.

(d) Revenue

Revenue from contracts with customers is recognised when the performance obligations are considered met, which is when control of the products or services provided are transferred to the customer. Revenue is recognised at an amount that reflects the consideration the Group expects to be entitled to, net of goods and services tax or similar taxes.

Where part or all of the transaction price is variable, revenue is recognised only to the extent that it is highly probable that a significant reversal of revenue will not occur.

Oil sales

Performance obligations are satisfied when the control of oil is transferred to the customer at the despatch point to the offtake vessel. The transaction price for oil sales may not be finalised at the date the customer takes control of the product. In such cases, a provisional transaction price is used until a final transaction price can be determined. The difference between the provisional and the final transaction price is recognised at the point when the final price is determined.

Credit terms for crude cargoes are between 30 and 45 days.

Interest Income

Interest income on financial assets at amortised cost calculated using the effective interest method is recognised in the consolidated statement of profit or loss and other comprehensive income as other income. Interest income is calculated by applying the effective interest rate to the gross carrying amount of the relevant financial asset, except for financial assets that subsequently become credit impaired. For credit-impaired financial assets the effective interest rate is applied to the net carrying amount of the financial asset (after deduction of the loss allowance).

(e) Foreign Currency Transactions and Balances

Functional and Presentation Currency

Items included in the financial statements of each of the Group's subsidiaries are measured using the currency of the primary economic environment in which the subsidiary or branch operates (the 'functional currency').

The functional currency of the Company is Australian dollars. The Group's Brazilian & Peruvian subsidiaries have a functional currency of US$.

The presentation currency of the consolidated financial statements is US$.

Transactions and Balances

Foreign currency transactions are translated into the functional currency using the foreign exchange rates prevailing at the dates of the transactions. Foreign currency gains and losses resulting from the settlement of such transactions and from the translation at financial year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in the consolidated statement of profit or loss and other comprehensive income, except when they are attributable to part of the net investment in a foreign operation.

Non-monetary items measured at historical cost continue to be carried at the foreign exchange rate at the date of the transaction. Foreign exchange differences arising on the translation of non-monetary items are recognised directly in equity to the extent that the gain or loss is directly recognised in equity, otherwise foreign exchange differences are recognised in the consolidated statement of profit or loss and other comprehensive income.

Foreign exchange gains and losses are presented in the consolidated statement of profit or loss and other comprehensive income on a net basis within other income or expenses.

Group Companies

The results and financial position of entities within the Group that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities are translated at the foreign exchange rates prevailing at the end of each reporting period;
- income and expenses are translated at the average foreign exchange rates for the financial period (unless this is not a reasonable approximation of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions); and
- all resulting foreign exchange differences are recognised in other comprehensive income.

On consolidation, foreign exchange differences arising on translation of foreign currency financial statements are transferred directly to the foreign currency translation reserve in the consolidated statement of financial position. The relevant differences are recognised in the consolidated statement of profit or loss and other comprehensive income during the financial period when the investment in the entity is disposed.

(f) Income Taxes and Other Taxes

Current Tax

Current tax (expense)/benefit is calculated by reference to the amount of income taxes payable or recoverable in respect of the taxable profit or loss for the financial period. It is calculated using income tax rates and tax laws that have been enacted or are substantively enacted by the end of each reporting period in the countries where the Company's subsidiaries operate and generate taxable income. Current tax for current and previous financial periods is recognised as a liability (or asset) to the extent that it is unpaid or refundable.

Deferred Tax

Deferred tax is accounted for using the statement of financial position liability method in respect of temporary differences arising between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. The tax base of an asset or liability is the amount attributed to that asset or liability for income taxation purposes.

No deferred tax is recognised from the initial recognition of an asset or liability, excluding a business combination, where there is no effect on accounting or taxable profit or loss.

Deferred tax is calculated at the tax rates that are enacted or substantively enacted by the end of the financial period and are expected to apply to the financial period when the asset is realised, or liability is settled. Deferred tax is credited in the consolidated statement of profit or loss and other comprehensive income except where it relates to items that may be credited directly to equity, in which case the deferred tax is adjusted directly against equity.

Deferred tax assets are recognised to the extent that it is probable that sufficient taxable amounts will be available against which deductible temporary tax differences or unused tax losses and tax offsets can be utilised.

Deferred tax assets and tax liabilities are offset when there is a legally enforceable right to offset current tax assets and tax liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the Group has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

The amount of benefits brought to account or which may be realised in the future is based on the assumption that no adverse change will occur in income taxation legislation and the anticipation that the Group will derive sufficient future assessable income to enable the benefit to be realised and comply with the conditions of deductibility imposed by law.

Tax Consolidation

The Company and its wholly owned Australian subsidiaries are part of an income tax-consolidated group under Australian taxation law. The Company is the head entity in the income tax-consolidated group. Tax (expense)/benefit, deferred tax liabilities and deferred tax assets arising from temporary tax differences of the members of the income tax-consolidated group are recognised in the separate financial statements of the members of the income tax-consolidated group using the 'stand-alone taxpayer' approach, by reference to the carrying amounts in the separate financial statements of each company and the tax values applying under tax consolidation. Current tax liabilities and tax assets and deferred tax assets arising from unused tax losses and tax credits of members of the income tax-consolidated group are recognised by the Parent Company (as head entity of the income tax-consolidated group).

Due to the existence of a tax funding agreement between the companies in the income tax-consolidated group, each company contributes to the income tax payable or receivable in proportion to their contribution to the income tax-consolidated group's taxable income. Differences between the amounts of net tax assets and tax liabilities derecognised and the net amounts recognised pursuant to the funding agreement are recognised as either a contribution by, or distribution to, the head entity.

Goods and Services Tax ('GST')

Revenues, expenses and assets are recognised net of the amount of GST, except where the amount of GST incurred is not recoverable from the Australian Taxation Office ('ATO'). In these circumstances, the GST is recognised as part of the cost of acquisition of the asset or equity or as part of an item of expense.

Receivables and payables in the consolidated statement of financial position are shown inclusive of GST.

The net amount of GST recoverable from, or payable to, the ATO, is included as current receivables or payables respectively in the consolidated statement of financial position.

Cash flows are included on a gross basis in the consolidated statement of cash flows. The GST components of cash flows arising from investing and financing activities, which are recoverable from, or payable to, the ATO, are classified as operating cash flows.

Commitments and contingencies are disclosed net of the amount of GST recoverable from, or payable to, the ATO.

(g) Cash and Cash Equivalents

Cash and cash equivalents in the consolidated statement of financial position and for presentation in the consolidated statement of cash flows comprise cash at bank and on hand (including share of joint operation cash balances) and short-term bank deposits that are readily convertible to known amounts of cash and are subject to insignificant risk of changes in value.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES CONTINUED

(h) Receivables

Receivables, which normally have 30-45 day terms, are generally non-interest-bearing amounts. They are recognised initially at the amount of the consideration that is unconditional unless they contain significant financing components, when they are recognised initially at fair value. The Group holds receivables with the objective to collect the contractual cash flows. They are presented as current assets unless collection is not expected for more than 12 months after reporting date. For receivables expected to be settled within 12 months, these are subsequently measured at amortised cost using the effective interest method, less any loss allowance. For receivables expected to be settled later than 12 months, these are subsequently measured at amortised cost based on discounted cash flows using an effective interest rate, less any loss allowance.

Cash flows relating to non-current receivables are not discounted if the effect of discounting would be immaterial. Refer Note 3(c) for a description of the Group's receivable impairment policies.

(i) Inventories

Inventories are measured at the lower of cost and net realisable value. Net realisable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and selling expenses.

Cost for petroleum products, which comprise extracted crude oil stored in the FPSO, are valued using the absorption cost method.

Other inventories are represented by assets acquired from third parties, in the form of casing and other drilling inventory to be consumed or used in exploration and evaluation activities or production activities. They are presented as current assets unless inventories are not expected to be consumed or used in exploration and evaluation activities within 12 months. The cost of casing and other drilling inventory includes direct materials, direct labour and transportation costs.

(j) Security Deposits

Certain financial assets have been pledged as security for performance guarantees, bank guarantees and bonds related to exploration tenements and operating lease rental agreements. Their realisation may be restricted subject to terms and conditions attached to the relevant exploration tenement agreements or operating lease rental agreements.

Security deposits are non-derivative financial assets that are not quoted in an active market. Security deposits are initially recognised at fair value. Such assets are subsequently carried at amortised cost using the effective interest method, less any loss allowance. They are included in current assets, except for those with maturities greater than 12 months after the end of the reporting period which are classified as non-current assets.

Security deposits are derecognised when the terms and conditions attached to the relevant exploration tenement agreements or lease rental agreements have expired or been transferred.

Refer Note 3(c) for a description of the Group's security deposit impairment policies.

(k) Property, Plant and Equipment

Property, plant and equipment is stated at cost less accumulated depreciation and any accumulated impairment losses. Such cost includes the cost of replacing parts that are eligible for capitalisation when the cost of replacing the parts is incurred. Similarly, when each major inspection is performed, its cost is recognised in the carrying amount of the plant and equipment as a replacement only if it is eligible for capitalisation. All other repairs and maintenance are recognised as an expense in the consolidated statement of profit or loss and other comprehensive income as incurred.

Commencing from the time the plant and equipment is held ready for use, depreciation expense is calculated on a straight-line basis to allocate their cost amount, net of their residual values, over their estimated useful lives ranging from 2 to 10 years.

Plant and equipment residual values, useful lives and depreciation methods are reviewed, and adjusted if appropriate, at the end of each reporting period.

Gains and losses on disposals are determined by comparing proceeds with the net carrying amount. These gains and losses are included in the consolidated statement of profit or loss and other comprehensive income.

Property, plant and equipment are tested for impairment in accordance with the accounting policy described in Note 1(p).

(l) Oil and Gas Assets

Production assets

Production assets are stated at cost less accumulated amortisation and impairment charges. Production assets include the costs to acquire, construct, install or complete production and infrastructure facilities, capitalised borrowing costs, transferred exploration and evaluation assets, development wells and the estimated cost of dismantling and restoration. Subsequent capital costs, including major maintenance, are included in the asset's carrying amount only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be reliably measured.

Assets in development

When the technical and commercial feasibility of an undeveloped oil or gas field has been demonstrated and approval of commercial development occurs, the field enters its development phase. The costs of oil and gas assets in development are separately accounted for and include past exploration and evaluation costs, development drilling and other subsurface expenditure, surface plant and equipment and any associated land and buildings. When the committed development expenditure programs are completed and commercial production commences, these costs are subject to amortisation.

Amortisation of production assets

Amortisation is calculated using the units of production method for an asset or group of assets from the date of commencement of production.

(m) Intangibles

Computer Software

Computer software is stated at cost less accumulated amortisation and any accumulated impairment losses. Computer software costs have a finite life.

Commencing from the time the computer software is held ready for use, amortisation expense is calculated on a straight-line basis to allocate their cost amount, net of their residual values, over their estimated useful lives ranging from 2 to 2.5 years.

The assets' residual values, useful lives and amortisation methods are reviewed, and adjusted if appropriate, at the end of each reporting period. Computer software is tested for impairment in accordance with the accounting policy described in Note 1(p).

(n) 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 are capitalised as part of the cost of the asset. All other borrowing costs are expensed in the period in which they occur. Borrowing costs consist of interest and other costs that an entity incurs in connection with the borrowing of funds.

(o) Exploration and Evaluation Expenditure

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. Expenditure in respect of each area of interest is accounted for using the 'successful efforts' method of accounting. The 'successful efforts' method requires all exploration and evaluation expenditure in relation to an area of interest to be expensed in the period it is incurred, except the cost of successful wells, the costs of acquiring interests in new exploration assets, and appraisal costs relating to determining development feasibility, which are capitalised as exploration and evaluation assets.

Exploration and evaluation assets are recognised in relation to an area of interest when the rights to tenure of the area of interest are current and either:

- it is expected to be recovered through sale or successful development and exploitation of the area of interest; or
- relates to an exploratory discovery for which at balance date a reasonable assessment of the existence or otherwise of economically recoverable reserves is not yet complete, or additional appraisal work is underway or planned.

All exploration expenditure in relation to directly attributable general administration costs, geological and geophysical costs, seismic and pre-tenure costs is expensed in the consolidated statement of profit or loss and other comprehensive income as incurred.

For exploration wells, costs directly associated with drilling the wells are initially capitalised on a well-by-well basis pending the evaluation of whether potentially economic reserves of hydrocarbons have been discovered. If no recoverable hydrocarbons are identified, or discoveries are deemed non-commercial, then the capitalised costs are expensed.

As capitalised exploration and evaluation expenditure is not available for use, it is not amortised.

Cash flows associated with exploration and evaluation expenditure expensed are classified as operating activities in the consolidated statement of cash flows. Whereas cash flows associated with capitalised exploration and evaluation expenditure are classified as investing activities.

When the technical feasibility and commercial viability of extracting economically recoverable reserves have been demonstrated, any related capitalised exploration and evaluation expenditure is reclassified as development expenditure in the consolidated statement of financial position. Prior to reclassification, capitalised exploration and evaluation expenditure is assessed for impairment.

Petroleum tenement acquisition costs are capitalised, along with licence costs paid in connection with a right to explore in an existing exploration area.

Farm-out

The Group does not record any exploration and evaluation expenditure made by a farmee, including any carries incurred by the farmee to earn an ownership interest.

Any cash consideration received on sale or farm-out of an area within an exploration area of interest is recognised as revenue in the consolidated statement of profit or loss and other comprehensive income, unless any of the consideration is attributable to capitalised exploration and evaluation expenditure. Cash consideration received in relation to capitalised exploration and evaluation expenditure is offset against the carrying value of the capitalised exploration and evaluation expenditure. Where the total carrying value has been recouped in this manner, the balance of the proceeds is brought to account as income as a gain on disposal.

Impairment of Capitalised Exploration and Evaluation Expenditure

The carrying value of capitalised exploration and evaluation expenditure is assessed for impairment at the asset level whenever facts and circumstances (as defined in AASB 6 *'Exploration for and Evaluation of Mineral Resources'*) suggest that the carrying amount of the asset may exceed its recoverable amount. If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES CONTINUED

An impairment loss exists when the carrying amount of an asset or cash-generating unit exceeds its estimated recoverable amount. The asset or cash-generating unit is then written-down to its recoverable amount. Impairment losses are recognised as an expense in the consolidated statement of profit or loss and other comprehensive income.

(p) Impairment of Assets (Other than Capitalised Exploration and Evaluation Expenditure)

All other current and non-current assets (other than receivables, inventories, security deposits and deferred tax assets) are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

At the end of each reporting period, the Group conducts an internal review of asset values, which is used as a source of information to assess for any indicators of impairment. External factors, such as changes in economic conditions, are also monitored to assess for indicators of impairment. If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated.

An impairment loss exists when the carrying amount of an asset or cash-generating unit exceeds its estimated recoverable amount. The asset or cash generating unit is then written down to its recoverable amount. Recoverable amount is the higher of an asset's fair value less costs of disposal and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows that are largely independent of the cash inflows from other assets or groups of assets (cash-generating units).

Impairment losses are recognised as an expense in the consolidated statement of profit or loss and other comprehensive income. Assets that suffered impairment are tested for possible reversal of the impairment loss whenever events or changes in circumstances indicate that the impairment may have reversed.

(q) Trade and Other Payables

Trade and other payables are initially recognised at their fair value and subsequently measured at amortised cost using the effective interest method. These amounts represent liabilities for goods and services provided to the Group prior to the end of the reporting period that are unpaid and arise when the Group becomes obliged to make future payments in respect of the purchase of goods and services. The amounts are unsecured and are usually paid within 30 days of recognition. They are presented as current liabilities unless payment is not due within twelve months from the reporting date.

(r) 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. A derivative embedded in a hybrid contract, with a financial liability or non-financial host, is separated from the host and accounted for as a separate derivative if the economic characteristics and risks are not closely related to the host, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the hybrid contract is not measured at fair value through profit or loss. Embedded derivatives are measured at fair value with changes in fair value recognised in profit or loss. 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.

For purposes of subsequent measurement, financial liabilities are classified in two categories: financial liabilities at fair value through profit or loss and financial liabilities at amortised cost (loans and borrowings).

The Group's financial liabilities include trade and other payables, borrowings, derivative financial instruments designated as cash flow hedges, and a derivative financial instrument relating to contingent consideration for the acquisition of an asset.

Derivatives designated as hedging instruments

The Group has entered into derivative financial instruments to hedge its exposure to cash flow risk from movements in oil price (commodity price risk) arising from highly probable forecasted future oil sales.

At the inception of a hedge relationship, the Group documents the risk management objective and strategy for undertaking the hedge transaction. The documentation includes identification of the hedging instrument, the hedged item, the nature of the risk being hedged and how the Group will assess whether the hedging relationship meets the hedge effectiveness requirements (including the analysis of sources of hedge ineffectiveness and how the hedge ratio is determined). A hedging relationship qualifies for hedge accounting if it meets all of the following effectiveness requirements:

- there is 'an economic relationship' between the hedged item and the hedging instrument.
- The effect of credit risk does not 'dominate the value changes' that result from that economic relationship.
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Group actually hedges and the quantity of the hedging instrument that the Group actually uses to hedge that quantity of hedged item.

Derivative financial instruments are presented as current assets or liabilities to the extent they are expected to be realised or settled within twelve months after the end of the reporting period. Hedges that meet all the qualifying criteria for hedge accounting are accounted for as described below.

Cash flow hedges

When a derivative is designated as a cash flow hedging instrument, the effective portion of changes in the fair value of the derivative is recognised in other comprehensive income ('OCI') and accumulated in the hedging reserve. The effective portion of changes in the fair value of the derivative that is recognised in OCI is limited to the cumulative change in fair value of the hedged item, determined on a present value basis, from inception of the hedge. Any ineffective portion of changes in the fair value of the derivative is recognised immediately in profit or loss. The Group designates only the change in fair value of the spot element of the derivative transaction contracts (the intrinsic value of the option) as the hedging instrument in cash flow hedging relationships. The change in fair value of the value of the option contract in relation to time value of money is separately accounted for as a cost of hedging and recognised in a costs of hedging reserve within equity.

For all financial hedged derivative transaction contracts, the amount accumulated in the hedging reserve and the cost of hedging reserve is reclassified to profit or loss in the same period or periods during which the hedged expected future cash flows affect profit or loss. If the hedge no longer meets the criteria for hedge accounting or the hedging instrument is sold, expires, is terminated or is exercised, then hedge accounting is discontinued prospectively. When hedge accounting for cash flows is discontinued, the amount that has been accumulated in the hedging reserve remains in equity until it is reclassified to profit or loss in the same period or periods as the hedged expected future cash flows affect profit or loss. If the hedged future cash flows are no longer expected to occur, then the amounts that have been accumulated in the hedging reserve and the cost of hedging reserve are immediately reclassified to profit or loss. Further details are disclosed in Note 22.

(s) Employee Benefits

Wages, Salaries, Annual Leave and Personal Leave

Liabilities for wages and salaries, including non-monetary benefits and annual leave expected to be settled within 12 months after the end of the reporting period in which the employees render the related services are recognised in respect of employees' services up to the end of the reporting period. They are measured at the amounts expected to be paid when the liabilities are settled plus related on-costs. Expenses for non-vesting personal leave are recognised when the leave is taken and are measured at the rates paid or payable.

The obligations are presented as current liabilities in the consolidated statement of financial position if the Group does not have an unconditional right to defer settlement for at least twelve months after the reporting date, regardless of when the actual settlement is expected to occur.

Share-based Payments

Share-based remuneration benefits are provided to Executive Directors and employees via the Company's PRP (refer Note 29). The Group issues equity-settled and cash-settled share-based payments to certain employees.

The fair value of performance rights granted is recognised as a share-based payments expense in the consolidated statement of profit or loss and other comprehensive income. The total amount to be expensed is determined by reference to the fair value of the performance rights granted, which includes any market performance conditions, but excludes the impact of any service and non-market performance vesting conditions. Non-market performance vesting conditions are included in assumptions about the number of performance rights that are expected to vest.

The fair value is measured at grant date. For equity-settled share-based payments the corresponding credit is recognised directly in the share-based payments reserve in equity. For cash-settled share-based payments a liability is recognised based on fair value of the payable earned by the end of the reporting period. The liability is re-measured to fair value at each reporting date up to, and including the vesting date, with changes in fair value recognised in share-based payments expense. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied. At the end of each reporting period, the Group revises its estimates of the number of performance rights that are expected to vest based on the non-market performance vesting conditions. It recognises the impact of the revision to original estimates, if any, in the consolidated statement of profit or loss and other comprehensive income.

The fair value of performance rights, granted for $nil consideration, at grant date is based on the Company's closing share price at that date, with the exception of long-term performance rights granted during the current financial year.

Long term performance rights granted during the current financial year, which are subject to market-based performance conditions, have been valued using a Monte Carlo simulation approach.

(t) Provisions

Provisions are recognised when the Group has a present obligation (legal or constructive) 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.

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES CONTINUED

Restoration Costs

A provision for restoration is provided by the Group where there is a present obligation as a result of exploration, development or production activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation. The estimated future obligations include the estimated costs of decommissioning and removing an asset and restoring the site. These costs are capitalised within the cost of the associated assets and the provision is stated in the consolidated statement of financial position at total estimated present value. These costs are based on judgements and assumptions regarding removal dates, technologies, industry practice and relevant legislation. Over time, the liability is increased for the change in the present value based on a risk adjusted pre-tax discount rate appropriate to the risks inherent in the liability. The costs of restoration are brought to account in the consolidated statement of comprehensive income through amortisation of the associated assets over the economic life of the projects with which these costs are associated. The unwinding of the discount is included as an accretion charge within finance costs.

Long Service Leave

A provision has been recognised for employee entitlements relating to long service leave measured at the discounted value of estimated future cash outflows. In determining the provision, consideration is given to employee wage increases and the probability that the employee may satisfy vesting requirements. The cash outflows are discounted using market yields with terms of maturity that match the expected timing of cash outflows.

Employee entitlements relating to long service leave are presented as a current provision in the consolidated statement of financial position if the Group does not have an unconditional right to defer settlement for at least twelve months after the reporting period, regardless of when the actual settlement is expected to occur.

(u) Contributed Equity

Ordinary shares are classified as equity.

Transaction costs directly attributable to the issue of new ordinary shares, share options or performance rights are shown in equity as a deduction, net of any related income tax, from the proceeds. Transaction costs are the costs that are incurred directly in connection with the issue of new ordinary shares, and which would not have been incurred had those ordinary shares not been issued. These directly attributable transaction costs include registration and other regulatory fees, amounts paid to legal, accounting and other professional advisers, printing costs and marketing costs.

Where the Company acquires its own ordinary shares, as a result of a share buy-back, those ordinary shares are cancelled. No gain or loss is recognised, and the consideration paid to acquire the ordinary shares, including any transaction costs directly attributable, net of any related income tax, is recognised directly as a reduction from equity.

(v) Interests in Joint Operations

A joint operation is a joint arrangement whereby the participants that have joint control of the arrangement (i.e. joint operators) have rights to the assets, and obligations for the liabilities, relating to the arrangement.

The Group recognises assets, liabilities, revenues and expenses according to its share in the assets, liabilities, revenues and expenses of a joint operation or similar as determined and specified in contractual arrangements (joint operating agreements). These have been incorporated in the consolidated financial statements under the appropriate headings.

(w) Leases

The Group has lease contracts for property, an FPSO vessel and other equipment used in its operations.

The Group recognises a right-of-use asset and a lease liability at the lease commencement date.

The lease liability is initially measured at the present value of the lease payments expected to be paid over the lease term, discounted using the interest rate implicit in the lease or, if the rate cannot be readily determined, the Group's estimated incremental borrowing rate. The lease liability is subsequently increased by the interest cost on the lease liability and decreased by lease payments made. The lease liability is further remeasured if the estimated future lease payments change as a result of index or rate changes, residual value guarantees or likelihood of exercise of purchase, extension or termination options.

The Group has applied judgement to determine the lease term for lease contracts that include renewal options. The assessment of whether the Group is reasonably certain to exercise such options impacts the lease term, which affects the measurement of lease liabilities and right-of-use assets recognised.

Right-of-use assets

The right-of-use asset is initially measured at cost (present value of the lease liability plus deemed cost of acquiring the asset), and subsequently at cost less any accumulated depreciation, impairment losses and adjustment for remeasurement of the lease liability.

Property leases generally have terms between 2 and 5 years. The FPSO vessel lease has a fixed term to February 2026 with renewal options available.

(x) Earnings Per Share

Basic Earnings Per Share

Basic earnings per ordinary share is calculated by dividing the profit or loss attributable to owners of the Company, excluding any costs of servicing equity other than ordinary shares, by the weighted average number of ordinary shares outstanding during the financial year, adjusted for any bonus elements in ordinary shares issued during the financial year.

Diluted Earnings Per Share

Diluted earnings per ordinary share adjusts the figures used in the determination of basic earnings per ordinary share to take into account the after-income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of ordinary shares that would have been outstanding assuming the conversion of all dilutive potential ordinary shares.

(y) Parent Company Financial Information

The financial information for the Parent Company, Karoon Energy Ltd, disclosed in Note 31 has been prepared on the same basis as the consolidated financial statements, except as set out below:

Investments in Subsidiaries

Investments in subsidiaries are accounted for at cost in the Parent Company's financial statements.

The Parent Company does not designate any investments in subsidiaries as being subject to the requirements of Australian Accounting Standards specifically applicable to financial instruments. They are held for strategic and not trading purposes.

Investments in subsidiaries and receivables from subsidiaries are tested for impairment in accordance with the accounting policy described in Note 1(p).

Share-based Payments

The grant by the Company of equity-settled performance rights over its ordinary shares to the employees of subsidiary companies in the Group is treated as a capital contribution to that subsidiary company. The fair value of employee services received, measured by reference to the grant date fair value, is recognised over the vesting period as an increase to investments in subsidiaries, with a corresponding credit to equity.

(z) New Australian Accounting Standards and Interpretations for Application in Future Financial Years

There are no relevant new Australian Accounting Standards or Interpretations that are not yet effective and that are expected to have a material impact on the Group in the current or future financial years and on foreseeable future transactions.

(aa) Comparative Figures

When required by Accounting Standards, comparative figures have been adjusted to conform to changes in presentation for the current period.

NOTE 2. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS

Revenues and expenses and the carrying amounts of certain assets and liabilities are often determined based on estimates and assumptions of future events. In applying the Group's significant accounting policies, the Board of Directors and management evaluate estimates and judgements based on historical knowledge and best available current information. Estimates assume a reasonable expectation of future events and are based on current trends and economic data obtained both externally and within the Group.

Significant estimates, assumptions and/or judgements made by the Board of Directors and management in the preparation of the consolidated financial statements were:

(a) Impairment of oil and gas assets

The Group assesses whether oil and gas assets are impaired at least on a semi-annual basis. This requires review of the indicators of impairment and/or an estimation of the recoverable amount of the cash-generating unit to which the assets belong. For oil and gas properties, expected future cash flow estimation is based on reserves, future production profiles, commodity prices and costs. Current climate change legislation is also considered in relation to oil price forecasts and the cash generating unit's useful life. Future uncertainty around climate change risks continue to be monitored.

(b) Capitalised Exploration and Evaluation Expenditure

Capitalised exploration and evaluation expenditure is carried forward on the basis that exploration and evaluation operations in the areas of interest have not at the end of the reporting period reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and active and significant operations in, or in relation to, the areas of interest are continuing.

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the related exploration tenement itself or, if not, whether it successfully recovers the related exploration and evaluation asset through sale. Factors that could affect the future recoverability include the level of economically recoverable reserves, future technological changes which could impact the cost of development, future legal changes (including changes to environmental and restoration obligations) and changes to commodity prices. To the extent that capitalised exploration and evaluation expenditure is determined not to be recoverable in the future, the relevant capitalised amount will be impaired in the consolidated statement of profit or loss and other comprehensive income and net assets will be reduced during the financial period in which this determination is made.

Information on the reasonable existence or otherwise of economically recoverable reserves is progressively gained through geological analysis and interpretation, drilling activity and prospect evaluation during a normal exploration tenement term. A reasonable assessment of the existence or otherwise of economically recoverable reserves can generally only be made, therefore, at the conclusion of those exploration and evaluation activities.

NOTE 2. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGEMENTS CONTINUED

(c) Provision for Restoration

Restoration costs are a normal consequence of operating in the oil and gas industry. A provision has been recognised for the Group's restoration obligations for the Baúna field.

In determining an appropriate level of provision, consideration is given to the expected future costs to be incurred, the timing of these expected future costs, the estimated future level of inflation and appropriate discount rate. The ultimate costs of restoration are uncertain and cost estimates could be subject to revisions in subsequent years due to many factors including changes to the relevant legal and legislative requirements, the emergence of new restoration techniques or experience at other fields. Risks associated with climate change also continue to be monitored. Likewise, the appropriate future discount rates used in the calculation are subject to change according to the risks inherent in the liability. The discount rate used to determine the restoration obligation at 30 June 2023 was based on applicable government bond rates with a tenure aligned to the tenure of the liability.

Changes to any of the estimates could result in a significant change to the level of provisioning required, which would in turn impact future financial results.

(d) Estimates of reserves quantities

The estimated quantities of Proved plus Probable ("2P") hydrocarbon reserves reported by the Group are integral to the calculation of amortisation expense and to the assessment of impairment or impairment reversals.

Estimated reserves quantities are based on management's interpretations of geological and geophysical models, reservoir engineering and production engineering analyses and models, and assessments of the technical feasibility and commercial viability of producing the reserves, taking into consideration reviews by an independent third party. An external reserves assessment is planned to be undertaken at least every 3 years.

Assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes. The Group prepares its reserves estimates in accordance with the Petroleum Resources Management System (PRMS 2018) published by the Society of Petroleum Engineers and the Australian Securities Exchange Listing rules. All estimates of reserves reported by the Group are prepared by, or under the supervision of, a qualified petroleum reserves and resources evaluator.

Estimates of reserves may change from period to period as the economic assumptions used to estimate the reserves can change from period to period, and as additional geological data is generated during the course of operations. These changes may impact depreciation, amortisation, asset carrying values, restoration provisions and deferred tax balances. If proved and probable reserves estimates are revised downwards, earnings could be affected by a higher depreciation and/or amortisation charge or immediate write-down of the assets carrying value.

(e) Fair value measurement of financial instruments

When the fair values of financial assets and financial liabilities recorded in the consolidated statement of financial position cannot be measured based on quoted prices in active markets, their fair value is measured using valuation techniques including the discounted cash flow model. The fair value of the contingent consideration (refer to Note 22) is based on the Group's internal assessment of future oil prices, which considers industry consensus and observable prices, inflation and an appropriate risk-free rate. Changes in assumptions relating to these factors could affect the reported fair value of the financial instrument.

(f) Share-based Payments

Estimating fair value for share-based payment transactions requires determination of the most appropriate valuation model, which depends on the terms and conditions of the grant. This estimate also requires determination of the most appropriate inputs to the valuation model including the expected life of the performance right, volatility and dividend yield and making assumptions about them at grant date. The fair value of long-term performance rights issued during the current financial year are valued using a Monte Carlo simulation approach taking into account the terms and conditions on which the performance rights were granted. The cumulative share-based payments expense recognised reflects the extent, in the opinion of management, to which the vesting period has expired and the number of and performance rights granted that will ultimately vest or be settled in cash. At the end of each reporting period, the unvested performance rights and cash-settled share-based payment liability are adjusted by the number forfeited during the reporting period to reflect the actual number of performance rights outstanding and cash liability to be settled. In addition, the fair value of cash-settled share-based payments are remeasured, up to the date of settlement, to reflect the cash liability at the end of each reporting period with changes in the fair value recognised in the profit or loss.

(g) Income Tax

The Group is subject to income taxes in Australia, Brazil and other jurisdictions where it has foreign operations. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Group estimates its tax liabilities based on the Group's understanding of the relevant tax laws. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax balances in the financial period in which such determination is made.

Assessing the future utilisation of tax losses and temporary tax differences requires the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws. To the extent that future utilisation of these tax losses and temporary tax differences becomes probable, this could result in significant changes to deferred tax assets recognised, which would in turn impact future financial results.

(h) Determining the lease term of contracts with renewal options

The Group determines the lease term as the non-cancellable term of the lease, together with any periods covered by an option to extend the lease if it is reasonably certain to be exercised, or any periods covered by an option to terminate the lease, if it is reasonably certain not to be exercised.

The Group has several lease contracts that include renewal options. The Group applies judgement in evaluating whether it is reasonably certain whether or not to exercise the option to renew the lease. That is, it considers all relevant factors that create an economic incentive for it to exercise the renewal. After the commencement date, the Group reassesses the lease term if there is a significant event or change in circumstances that is within its control and affects its ability to exercise or not to exercise the option to renew or to terminate. The Group included the renewal periods as part of the lease term for the FPSO right-of-use asset as there will be a significant negative effect on production if a replacement asset is not readily available.

NOTE 3. FINANCIAL RISK MANAGEMENT

The Group's activities expose it to a variety of financial risks: market risk (including foreign exchange risk and interest rate risk); commodity price risk; credit risk; and liquidity risk. The Group's overall financial risk management program focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the financial performance of the Group. The Group uses different methods to measure the different types of financial risk to which it is exposed. These methods include sensitivity analysis in the case of foreign exchange, interest rates and commodity prices.

The overall financial risk management strategy of the Group is governed by the Board of Directors through the Audit, Risk and Governance Committee and is primarily focused on ensuring that the Group is able to finance its business plans, while minimising potential adverse effects on financial performance. The Board of Directors provides written principles for overall financial risk management, as well as written policies covering specific areas, such as mitigating foreign exchange, interest rate, commodity price and credit risks, use of derivative financial instruments and investment of excess cash. Financial risk management is carried out by the Company's finance function under policies approved by the Board of Directors. The finance function identifies, evaluates and if necessary, hedges financial risks in close co-operation with the Chief Executive Officer and Managing Director. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and Group activities.

Details of the significant accounting policies and methods adopted, including the criteria for recognition, the basis of measurement and the basis on which income and expenses are recognised in respect of each class of financial asset and financial liability are disclosed in Note 1.

The Group's financial instruments consist of cash and cash equivalents, receivables, security deposits, trade and other payables, lease liabilities, borrowings, derivative financial instruments designated as cash flow hedges, and embedded derivatives.

NOTE 3. FINANCIAL RISK MANAGEMENT CONTINUED

The totals for each category of financial instruments in the consolidated statement of financial position are as follows:

		CONSOLIDATED	
	NOTE	2023 US$M	2022 US$M
Financial assets			
Cash and cash equivalents	10	**74.8**	157.7
Receivables	11	**71.1**	56.4
Other financial assets	22	**3.0**	–
Security deposits	13	**2.7**	1.6
Total financial assets		**151.6**	215.7
Financial liabilities			
Trade and other payables (refer note (i) below)		**61.4**	73.6
Borrowings (refer note (ii) below)	21	**30.0**	30.0
Other financial liabilities (refer note (iii) below)	22	**219.0**	347.4
Lease liabilities	20	**247.6**	288.9
Total financial liabilities		**558.0**	739.9

(i) Trade and other payables above exclude amounts relating to annual leave liabilities, which are not considered a financial instrument.

(ii) Borrowings exclude transaction costs which are not considered a financial instrument.

(iii) Other financial liabilities relate to the contingent consideration payable to Petrobras as part of the acquisition of Baúna. (refer Note 22).

(a) Market Risk

(i) Foreign Exchange Risk

Foreign exchange risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. Foreign exchange risk arises when future commercial transactions and recognised financial assets and financial liabilities are denominated in a currency that is not the Company's functional currency.

The Group's revenue, significant operating expenditure including the FPSO charter lease and a large component of capital obligations are predominantly denominated in US$.

The Group's remaining foreign exchange risk exposures relate to administrative and business development expenditures incurred at the corporate level in A$; and operating and capital expenditures incurred by the Group in relation to operating the Baúna production asset in Brazil in Brazilian REAL. These items are translated to US$ equivalents at each period end, and the associated gain or loss is taken to the Consolidated Statement of Profit and Loss and Other Comprehensive Income.

The Group manages foreign exchange risk at the corporate level by monitoring forecast cash flows in currencies other than US$ and ensuring that adequate Brazilian REAL and A$ cash balances are maintained. Foreign currencies are bought on the spot market in excess of immediate requirements. Where currencies are purchased in advance of requirements, these balances do not usually exceed 3 months' requirements. The appropriateness of A$ and Brazilian REAL holdings are reviewed regularly against future commitments and current $A and Brazil REAL market expectations.

Periodically, sensitivity analysis is conducted to evaluate the potential impact of unfavourable exchange rates on the Group's future financial position. The results of this evaluation are used to determine the most appropriate risk mitigation tool to be used. The Group will hedge when it is deemed the most appropriate risk mitigation tool to be used. Foreign currency hedging transactions were not entered into during the financial year or previous financial year.

The Group is not exposed to material translation exposures at the end of the current financial year as the majority of its financial assets and liabilities are denominated in US$ and as such, no foreign currency sensitivity analysis has been disclosed.

(ii) Interest Rate Risk

Interest rate risk is the risk that the fair value of future cash flows of financial assets and financial liabilities will fluctuate because of changes in market interest rates. Interest rate risk is managed on a Group basis at the corporate level. This risk is managed through the use of cash flow forecasts supplemented by sensitivity analysis.

As at 30 June 2023 and 30 June 2022, there was no interest rate hedging in place.

The Group's interest rate risk arises from long-term borrowings at floating rates and cash and cash equivalents and security deposits which earn interest at floating rates. As long-term borrowings and the majority of cash and cash equivalents are held in US$'s, the primary exposure is to US$ interest rates.

An analysis of the Group's exposure to interest rate risk for financial assets and financial liabilities at the end of the financial year is set out below:

	CONSOLIDATED					
2023	**WEIGHTED AVERAGE INTEREST RATE % P.A.**	**FLOATING INTEREST RATE US$M**	**FIXED INTEREST RATE US$M**	**NON-INTEREST BEARING US$M**	**FAIR VALUE US$M**	**CARRYING AMOUNT US$M**
Financial assets						
Cash and cash equivalents	**1.39**	**27.0**	**–**	**47.8**	**74.8**	**74.8**
Receivables	**–**	**–**	**–**	**71.1**	**71.1**	**71.1**
Other financial assets	**–**	**–**	**–**	**3.0**	**3.0**	**3.0**
Security deposits	**9.07**	**2.6**	**0.1**	**–**	**2.7**	**2.7**
Total financial assets		**29.6**	**0.1**	**121.9**	**151.6**	**151.6**
Financial liabilities						
Trade and other payables	**–**	**–**	**–**	**61.4**	**61.4**	**61.4**
Borrowings	**8.22**	**30.0**	**–**	**–**	**30.0**	**30.0**
Other financial liabilities	**2.00**	**–**	**219.0**	**–**	**219.0**	**219.0**
Lease liabilities	**–**	**–**	**–**	**247.6**	**247.6**	**247.6**
Total financial liabilities		**30.0**	**219.0**	**309.0**	**558.0**	**558.0**

	CONSOLIDATED					
2022	**WEIGHTED AVERAGE INTEREST RATE % P.A.**	**FLOATING INTEREST RATE US$M**	**FIXED INTEREST RATE US$M**	**NON-INTEREST BEARING US$M**	**FAIR VALUE US$M**	**CARRYING AMOUNT US$M**
Financial assets						
Cash and cash equivalents	–	47.0	–	110.7	157.7	157.7
Receivables	–	–	–	56.4	56.4	56.4
Security deposits	7.09	1.5	0.1	–	1.6	1.6
Total financial assets		48.5	0.1	167.1	215.7	215.7
Financial liabilities						
Trade and other payables	–	–	–	73.6	73.6	73.6
Borrowings	5.95	30.0	–	–	30.0	30.0
Other financial liabilities	2.00	–	298.3	49.1	347.4	347.4
Lease liabilities	–	–	–	288.9	288.9	288.9
Total financial liabilities		30.0	298.3	411.6	739.9	739.9

NOTE 3. FINANCIAL RISK MANAGEMENT CONTINUED

Interest Rate Sensitivity Analysis

The following table details the Group's sensitivity to a 1% p.a. increase or decrease in interest rates, with all other variables held constant. The sensitivity analysis is based on the balance of floating interest rate amounts held at the end of the financial year.

The sensitivity analysis is not fully representative of the inherent interest rate risk, as the financial year end exposure does not necessarily reflect the exposure during the course of a financial year. These sensitivities should not be used to forecast the future effect of movements in interest rates on future cash flows.

	CONSOLIDATED	
	2023 US$M	2022 US$M
Change in profit(loss) before income tax		
– Increase of interest rate by 1% p.a.	–	0.4
– Decrease of interest rate by 1% p.a.	–	(0.1)
Change in financial instruments		
– Increase of interest rate by 1% p.a.	–	0.4
– Decrease of interest rate by 1% p.a.	–	(0.1)

(b) Commodity Price Risk

The Group is exposed to commodity price fluctuations associated with the production and sale of oil. Commodity price risk is managed on a Group basis at the corporate level. To mitigate commodity price risk, during the prior year, the Group entered into Brent oil price cash flow hedges, via a collar structure consisting of bought put and sold call options covering the period from December 2021 to March 2024. During the financial year, approximately 37% of actual production volume was hedged. At reporting date, the Group held hedging financial instruments with a net asset carrying value of $3.0m (refer Note 22).

Commodity Price Sensitivity Analysis – Cash Flow Hedges

The following table details the Group's sensitivity to a 10% increase or decrease in the Brent oil price, with all other variables held constant.

	CONSOLIDATED	
	2023 US$M	2022 US$M
Change in reserves (in accordance with hedge accounting application)		
– Increase of oil price by 10%	–	(47.8)
– Decrease of oil price by 10%	–	47.8
Change in financial liabilities		
– Increase of oil price by 10%	–	(47.8)
– Decrease of oil price by 10%	–	47.8

Commodity Price Sensitivity Analysis – Contingent Consideration

As part of the acquisition of Baúna, the Group agreed to pay Petrobras contingent consideration of up to $285 million plus interest of 2% per annum accruing from 1 January 2019. The fair value of the contingent consideration has been accounted for as an embedded derivative and estimated by calculating the present value of the future expected cash outflows. The estimates are based on the Group's internal assessment of future oil prices. A discount rate of 3.42% and 2% inflation factor has also been applied. Refer to Note 22 for more details.

The following table details the Group's sensitivity to a 10% increase or decrease in its internal assessment of future oil prices on the contingent consideration payable to Petrobras. At 30 June 2023, with the US$70 per barrel threshold triggered over calendar years 2022-2026, the maximum contingent consideration payable has been recognised and as such a 10% increase in the oil price would have no impact on the financial statements.

	CONSOLIDATED	
	2023 US$M	**2022 US$M**
Change in profit/(loss) before income tax		
– Increase of oil price by 10%	**–**	–
– Decrease of oil price by 10%	**30.4**	43.1
Change in financial liabilities		
– Increase of oil price by 10%	**–**	–
– Decrease of oil price by 10%	**(30.4)**	(43.1)

(c) Credit Risk

The maximum exposure to credit risk at the end of the financial year is the carrying amount of the financial assets as disclosed in the consolidated statement of financial position and notes to the consolidated financial statements.

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. Credit risk arises from cash and cash equivalents and security deposits held with banks, financial institutions and joint operators, as well as credit exposures to customers, including outstanding receivables and refundable tax credits.

Credit risk is managed on a Group basis at the corporate level. To minimise credit risk, the Group has adopted a policy of only dealing with recognised and creditworthy third parties. Receivable balances are monitored on an ongoing basis with the result being the Group's exposure to bad debts is minimised. The Group does not currently hold collateral, nor does it securitise its receivables.

The Group has policies in place to ensure that services are made to customers with an appropriate credit history.

Cash and cash equivalents and security deposit counterparties are limited to credit quality banks and financial institutions. For banks and financial institutions in Australia, only independently rated counterparties with a minimum rating of Aa3/A2 are accepted. For banks and financial institutions in Brazil, only independently rated counterparties with a minimum rating of Baa1 are accepted. For banks and financial institutions in Brazil, with independently rated counterparty ratings below Baa1, exposure cannot exceed the short-term country specific cash requirements unless they are associated banks of an International Bank with a higher credit rating. Cash and cash equivalents are held offshore by the Group's Brazilian subsidiary out of London with an International Bank with a rating of Baa1. The Group's credit exposure and external credit ratings of its counterparties are monitored on a periodic basis. Where commercially practical, the Group seeks to limit the amount of credit exposure to any one bank or financial institution.

(i) Impairment of Financial Assets

The Group has two types of financial assets that are subject to AASB 9's 'expected credit loss' model: receivables and security deposits. The Group has applied the AASB 9 general model approach to measuring expected credit losses for all receivables and security deposits.

While cash and cash equivalents are also subject to the impairment requirements of AASB 9, the identified impairment loss was considered not significant given the counterparties and/or the short maturity.

Expected Credit Loss

When required, the carrying amount of the relevant financial asset is reduced through the use of a loss allowance account and the amount of any loss is recognised in the consolidated statement of profit or loss and other comprehensive income. When measuring expected credit losses, balances are reviewed based on available external credit ratings, historical loss rates and the days past due.

Security Deposits

The Group's security deposits held in Australia are considered to have low credit risk on the basis that there is a low risk of default with the relevant bank counterparty. Management considers 'low credit risk' for security deposits with banks and financial institutions to be an investment grade credit rating with at least 1 major rating agency.

The Group is exposed to credit risk in relation to a security deposit of $2.1m (30 June 2022: $1.2m) held with Itau Unibanco SA in Brazil. The Group provided the ANP (the Brazilian oil and gas regulator) a letter of credit to carry out the minimum work program in relation to exploration in Santos Basin Block S-M-1537. The letter of credit is fully funded by way of payment of a security deposit (refer Note 13(b)), which will be released once the work program is met.

NOTE 3. FINANCIAL RISK MANAGEMENT CONTINUED

The credit rating of Itau Unibanco SA is Ba2 (30 June 2022: Ba2), which is a non-investment grade rating that carries credit risk. The credit rating of Itau Unibanco SA in Brazil is monitored on a periodic basis for credit deterioration. In addition, Management continually monitors Brazilian macro-economic factors for any deterioration which directly impacts the credit ratings of Brazilian financial institutions as bank credit ratings will be limited by the sovereign rating. As there has not been a significant increase in credit risk since initial recognition of this security deposit, which is predominantly impacted by negative macro-economic factors in Brazil, any impairment test uses a 12-month expected credit loss model measure.

As at 30 June 2023, there were $Nil (30 June 2022: $Nil) security deposits past due. The loss allowance recognised during the financial year for security deposits was $Nil. Accordingly, interest income has been calculated on the gross carrying amount during the financial year.

Receivables

The Group's receivables relating to Brazil and Australia are considered to have low credit risk on the basis that there is a low risk of default and the debtor has a strong (robust) capacity to meet its obligations in the short-term. Accordingly, for receivables any impairment test uses a 12-month expected credit loss model measure.

The Group is exposed to credit risk in relation to an interest receivable of $165k (30 June 2022: $318k) predominantly related to the security deposit held with Itau Unibanco SA in Brazil. As there has not been a significant increase in credit risk since initial recognition of the security deposit, which is predominantly impacted by negative macro-economic factors in Brazil, any impairment test uses a 12-month expected credit loss model measure.

As at 30 June 2023, there were $Nil (30 June 2022: $Nil) receivables past due. The loss allowance for receivables recognised during the financial year was $Nil (30 June 2022: $Nil).

(d) Liquidity Risk

Liquidity risk is the risk that the Group will encounter difficulty in meeting obligations associated with financial liabilities.

The Group manages liquidity risk by ensuring that there are sufficient funds available to meet financial obligations on a day-to-day basis and to meet unexpected liquidity needs in the normal course of business. Emphasis is placed on ensuring there is sufficient funding in place to meet the ongoing operational requirements of the Group's production activities, exploration, evaluation and development expenditure, and other corporate initiatives.

The following mechanisms are utilised to manage liquidity risk:

- preparing and maintaining rolling forecast cash flows in relation to operational, investing and financing activities;
- comparing the maturity profile of financial liabilities with the realisation profile of financial assets;
- managing credit risk related to financial assets;
- when necessary, utilising short-term and long-term loan facilities;
- investing surplus cash only in credit quality banks and financial institutions; and
- maintaining a reputable credit profile.

At the end of the financial year, the Group held cash and cash equivalents at call of $74.8m (30 June 2022: $157.7m) that are expected to readily generate cash inflows for managing liquidity risk. The Group had external borrowings of $30.0m (30 June 2022: $30.0m).

The Group had access to the following undrawn borrowing facilities at the end of the reporting period:

	2023 US$M	2022 US$M
Floating rate		
– Expiring beyond one year (syndicated loan facility and accordion facility)	**180.0**	180.0

An analysis of the Group's financial liabilities contractual maturities at the end of the financial year is set out in the tables below. The amounts disclosed in the table are the contractual undiscounted cash flows comprising principal and interest repayments.

	CONSOLIDATED					
2023	**LESS THAN 6 MONTHS US$M**	**6-12 MONTHS US$M**	**1-3 YEARS US$M**	**3-5 YEARS US$M**	**OVER 5 YEARS US$M**	**TOTAL US$M**
Financial liabilities						
Non-derivative financial liabilities						
Trade and other payables	**58.4**	**3.0**	**10.4**	**–**	**–**	**71.8**
Borrowings	**–**	**–**	**30.0**	**–**	**–**	**30.0**
Lease liabilities	**30.2**	**29.9**	**119.8**	**103.2**	**–**	**283.1**
Derivative financial liabilities						
Contingent consideration – embedded derivative	**–**	**86.0**	**128.8**	**17.5**	**–**	**232.3**
Total financial liabilities	**88.6**	**118.9**	**289.0**	**120.7**	**–**	**617.2**
2022						
Financial liabilities						
Non-derivative financial liabilities						
Trade and other payables	69.3	3.3	8.0	–	–	80.6
Borrowings	–	–	30.0	–	–	30.0
Lease liabilities	29.8	29.4	119.0	118.4	43.1	339.7
Derivative financial liabilities						
Derivative financial instruments – cash flow hedges	20.6	20.2	8.3	–	–	49.1
Contingent consideration – embedded derivative	–	84.6	174.4	59.1	–	318.1
Total financial liabilities	119.7	137.5	339.7	177.5	43.1	817.5

(e) Fair Value Estimation

For disclosure purposes only, the fair values of financial assets and financial liabilities as at 30 June 2023 and 30 June 2022 are presented in the table under Note 3(a)(ii) and can be compared to their carrying values as presented in the consolidated statement of financial position. Fair values are those amounts at which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's length transaction. Fair values estimated for disclosure purposes are based on information that is subject to judgement, where changes in assumptions may have a material impact on the amounts estimated.

The following summarises the significant methods and assumptions used in estimating fair values of financial assets and financial liabilities for disclosure purposes:

Cash and Cash Equivalents

The carrying amount is fair value due to the liquid nature of these assets.

Receivables

The carrying amounts of current receivables are assumed to approximate their fair values due to their short-term nature.

NOTE 3. FINANCIAL RISK MANAGEMENT CONTINUED

Security Deposits

The carrying amounts of security deposits are assumed to represent their fair values based on their likely realisability profile.

Trade and Other Payables

Due to the nature of these financial liabilities, their carrying amounts are a reasonable approximation of their fair values.

Lease Liabilities

Fair value is calculated based on the present value of the lease payments expected to be paid over the lease term, discounted using the interest rate implicit in the lease or, if the rate cannot be readily determined, the Group's estimated incremental borrowing rate.

Derivative Financial Instruments – Cash Flow Hedges

The fair value of derivative financial instruments designated as cash flow hedges are obtained from third party valuations. The fair value is determined using valuation techniques which maximise the use of observable market data.

Other Financial Liabilities – Embedded Derivative

The fair value of the contingent consideration was estimated by calculating the present value of the future expected cash outflows. The estimates are based on the Group's internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts. A discount rate of 3.42% and 2% inflation factor has also been applied.

Fair value measurement

The Group uses the following hierarchy for determining and disclosing the fair value of financial instruments by valuation technique:

- Level 1: fair value measurements are those derived from quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2: fair value measurements are those derived from inputs other than quoted prices included within Level 1 which are observable for the asset or liability, either directly or indirectly; and
- Level 3: fair value measurements are those derived from valuation techniques which include inputs for the asset or liability that are not based on observable market data.

All of the Group's financial instruments were valued using the Level 2 valuation technique.

NOTE 4. REVENUE AND OTHER INCOME

	CONSOLIDATED	
	2023 US$M	**2022 US$M**
(a) Revenue		
Crude oil sales	**566.5**	385.1
Total revenue from contracts with customers	**566.5**	385.1
(b) Other Income		
Interest income	**4.0**	0.2
Write-back of inventory impaired	**1.6**	–
Sundry income	**0.1**	0.6
Total other income	**5.7**	0.8

NOTE 5. EXPENSES

	CONSOLIDATED	
	2023 US$M	2022 US$M
(a) Cost of sales		
Operating costs	**62.0**	57.2
Royalties and other government take	**66.7**	41.5
Depreciation and amortisation – oil and gas assets	**143.0**	99.4
Change in inventories	**11.5**	(6.4)
Total cost of sales	**283.2**	191.7
(b) Business development and other project costs		
Business development and other project costs	**3.7**	3.4
Total Business development and other project costs	**3.7**	3.4
(c) Exploration expenses		
Exploration and evaluation expenditure expensed	**3.9**	3.2
Total exploration and evaluation expenditure expensed	**3.9**	3.2
(d) Finance costs		
Finance charges on lease liabilities	**15.5**	16.9
Discount unwinding on net present value of provision for restoration	**5.0**	2.4
Interest expense	**2.1**	2.1
Other finance costs	**2.8**	1.3
Total finance costs	**25.4**	22.7
(e) Other expenses		
Corporate	**20.7**	15.4
Realised losses on cash flow hedges	**7.1**	11.8
Depreciation and amortisation – non-oil and gas assets	**0.9**	0.7
Share-based payments expense	**3.1**	5.7
Social investments/sponsorships	**1.9**	–
Loss on disposal of non-current assets	**0.1**	–
Other expenses	**–**	0.2
Total other expenses	**33.8**	33.8

NOTE 6. INCOME TAX

	NOTE	CONSOLIDATED 2023 US$M	CONSOLIDATED 2022 US$M
(a) Income Tax Recognised in the Consolidated Statement of Profit or Loss and Other Comprehensive Income			
Tax income (expense) comprises:			
Current income tax		**(74.0)**	(39.3)
Deferred income tax		**20.8**	64.7
Total income tax (expense)/benefit		**(53.2)**	25.4
The prima facie tax on profit/(loss) before income tax is reconciled to tax (expense)/benefit as follows:			
Prima facie tax (expense)/benefit on profit/(loss) before income tax, calculated at the Brazilian tax rate of 34%(i)		**(73.5)**	30.5
(Add)/subtract the tax effect of:			
Share-based payments expense (non-cash)		**(0.7)**	(0.9)
Other non-deductible items		**(1.4)**	(3.4)
Social investments/sponsorships(ii)		**1.1**	–
Tax losses and temporary tax differences not recognised		**–**	(0.2)
Difference in overseas tax rates		**(0.4)**	(0.3)
Foreign exchange differences		**21.7**	(0.3)
Total income tax (expense)/benefit		**(53.2)**	25.4
(b) Amounts Recognised Directly in Equity			
Aggregate current and deferred tax arising during the financial year and not recognised in net profit or loss, but directly debited or credited in equity:			
Deferred tax – (debited)/credited directly in hedging reserves	23(d)(iii)	**(16.9)**	21.2

(i) In prior years, the reconciliation of prima facie tax (expense)/benefit on profit/(loss) before income tax to tax (expense)/benefit has been calculated at the Australian tax rate of 30%. Due to the current operations of the Company being predominantly located in Brazil, the Company has determined that the Brazilian tax rate of 34% provides the most meaningful information to users of the financial statements. The prior year comparatives in Note 6(a) have been restated.

(ii) This is a scheme which under Brazilian tax law permits a company when paying tax to direct a portion of this payment to specific government approved projects. There is no net cost to the Company as this amount replaces tax payable. It is classified as an expense in the financial statements

	BALANCE AS AT 1 JULY 2022 US$M	CHARGED (CREDITED) TO PROFIT OR LOSS US$M	CHARGED (CREDITED) DIRECTLY TO EQUITY US$M	TAX LOSSES UTILISED US$M	BALANCE AS AT 30 JUNE 2023 US$M
(c) Deferred Tax Balances					
Temporary differences					
Provisions and accruals	19.6	11.4	–	–	**31.0**
Equity raising transaction costs	0.2	(0.1)	–	–	**0.1**
Unrealised foreign currency (gains)/losses	(12.7)	(8.0)	–	–	**(20.7)**
Translation adjustment	14.2	24.6	–	–	**38.8**
Fair value movement of financial liabilities	79.6	(18.2)	–	–	**61.4**
Farm-out expenditures	0.1	–	–	–	**0.1**
Right-of-use assets	(95.4)	15.5	–	–	**(79.9)**
Lease liabilities	98.2	(3.6)	–	–	**94.6**
Hedge premium	(4.5)	(0.8)	–	–	**(5.3)**
Net changes of cash flow hedges	21.2	–	(16.9)	–	**4.3**
Other	0.3	–	–	–	**0.3**
Total temporary differences	120.8	20.8	(16.9)	–	**124.7**
Unused tax losses					
Tax losses	2.2	–	–	(2.2)	**–**
Total unused tax losses	2.2	–	–	(2.2)	**–**
Net deferred tax assets/(liabilities)	123.0	20.8	(16.9)	(2.2)	**124.7**
Presented in the consolidated statement of financial position as follows:					
Deferred tax assets	123.0				124.7

	CONSOLIDATED	
	2023 US$M	2022 US$M
(d) Unrecognised Deferred Tax Assets		
A deferred tax asset has not been recognised in the consolidated statement of financial position as the benefits of which will only be realised if the conditions for deductibility set out in Note 1(f) occur:		
Unrecognised temporary tax differences relating to deferred tax assets at a tax rate of 34%	**16.5**	18.0
Tax losses: Peruvian operating losses at a tax rate of 32%	**6.4**	6.4
Potential tax income	**22.9**	24.4

NOTE 7. REMUNERATION OF EXTERNAL AUDITORS

	CONSOLIDATED 2023 US$'000	2022 US$'000
Remuneration received or due and receivable by the external auditor of the Company for:		
(a) PricewaterhouseCoopers Australia		
(i) Audit and other assurance services		
Audit and review of financial statements	**190**	181
Other assurance services	**27**	36
Total remuneration for audit and other assurance services	**217**	217
(ii) Other services		
All other services	**–**	–
Total remuneration of PricewaterhouseCoopers Australia	**217**	217
(b) Related Practices of PricewaterhouseCoopers Australia		
(i) Audit and other assurance services		
Audit and review of financial statements	**151**	130
Total remuneration for audit and other assurance services of related practices of PricewaterhouseCoopers Australia	**151**	130
Total remuneration of external auditors	**368**	347

NOTE 8. DIVIDENDS

There were no ordinary dividends declared or paid during the financial year by the Group (2022: $Nil).

	CONSOLIDATED 2023 US$M	2022 US$M
Balance of franking account available for subsequent reporting periods	**14.4**	12.4

The above amount is calculated from the balance of the Company's franking account as at the end of the financial year. Franking credits are based on the Australian tax rate of 30%.

NOTE 9. EARNINGS PER SHARE

	CONSOLIDATED 2023 US$M	2022 US$M
Profit/(loss) for the financial year used to calculate basic and diluted earnings per ordinary share:	**163.0**	(64.4)
(a) Basic earnings per ordinary share (cents per share)	**28.99**	(11.59)
(b) Diluted earnings per ordinary share (cents per share)*	**28.59**	(11.59)
Weighted average number of ordinary shares on issue during the financial year used in calculating basic earnings per ordinary share:	**562,290,221**	555,904,067
Weighted average number of potential ordinary shares:	**7,816,439**	12,154,223
Weighted average number of ordinary shares and potential ordinary shares used in calculating diluted earnings per ordinary share:	**570,106,660**	568,058,290

* Diluted loss per ordinary share equates to basic loss per ordinary share in the prior financial year because a loss per ordinary share is not considered dilutive for the purposes of calculating earnings per share pursuant to AASB 133 *'Earnings per Share'*.

Potential ordinary shares

Performance rights over unissued ordinary shares of the Company outstanding at the end of the financial year are considered to be potential ordinary shares and have been included in the determination of diluted earnings per ordinary share to the extent to which they are dilutive. The potential ordinary shares have not been included in the determination of basic earnings per ordinary share.

NOTE 10. CASH AND CASH EQUIVALENTS

	CONSOLIDATED	
	2023 US$M	2022 US$M
Cash at bank and on hand	**74.8**	157.7
Total cash and cash equivalents	**74.8**	157.7

NOTE 11. RECEIVABLES

	CONSOLIDATED	
	2023 US$M	2022 US$M
Trade debtors – crude oil sales	**69.6**	56.0
Other receivables	**1.5**	0.4
Total current receivables	**71.1**	56.4

(a) Financial Risk Management

Information concerning the Group's exposure to financial risks on receivables is set out in Note 3.

NOTE 12. INVENTORIES

	CONSOLIDATED	
	2023 US$M	2022 US$M
Current		
Petroleum inventories	**5.8**	17.3
Casing and other drilling inventory	**2.9**	2.1
Total current inventories	**8.7**	19.4
Non-current		
Casing and other drilling inventory	**8.3**	5.8
Total non-current inventories	**8.3**	5.8

NOTE 13. SECURITY DEPOSITS

	CONSOLIDATED	
	2023 US$M	2022 US$M
Current		
Karoon Petróleo & Gás Ltda (refer note (a) below)	**0. 4**	0.3
Total current security deposits	**0.4**	0.3
Non-current		
Karoon Petróleo & Gás Ltda (refer note (b) below)	**2.1**	1.2
Karoon Energy Ltd (refer note (c) below)	**0.2**	0.1
Total non-current security deposits	**2.3**	1.3

(a) Bonds

Cash deposits are held as bonds predominately for the Group's compliance with its obligations in respect of agreements for the guarantee (refer Note 26) of payment obligations for office premises in Brazil.

(b) Guarantee Bond

The Group has provided the ANP a letter of credit (refer Note 26) to carry out the minimum work program in relation to exploration in Santos Basin Block S-M-1537. The letter of credit is fully funded by way of payment of a security deposit, which will be released once the work program is met.

(c) Bank Guarantees

Cash deposits are held as security against bank guarantee facilities for bank guarantees (refer Note 26) given to lessors for the Group's compliance with its obligations in respect of lease rental agreements for office premises in Australia.

(d) Financial Risk Management

Information concerning the Group's exposure to financial risks on security deposits is set out in Note 3.

NOTE 14. OTHER ASSETS

	CONSOLIDATED	
	2023 US$M	2022 US$M
Current		
Prepayments	**7.2**	9.3
Sundry assets	**2.0**	2.5
Total current other assets	**9.2**	11.8
Non-current		
Prepayments	**0.7**	1.3
Total non-current other assets	**0.7**	1.3

NOTE 15. OIL AND GAS ASSETS

	NOTE	PRODUCTION ASSET US$M	DEVELOPMENT ASSET US$M	RIGHT OF USE ASSETS US$M	CONSOLIDATED TOTAL US$M
Financial year ended 30 June 2022					
Balance at beginning of financial year		411.7	19.0	305.7	736.4
Additions	25(c)	69.3	22.7	–	92.0
Remeasurement of lease arrangements		–	–	20.8	20.8
Borrowing costs capitalised[(i)]		–	4.8	–	4.8
Depreciation expense		(55.0)	–	(44.4)	(99.4)
Impact of increase in discount rate on provision for restoration at year end	19(b)	(21.6)	–	–	(21.6)
Carrying amount at end of financial year		404.4	46.5	282.1	733.0
At 30 June 2022					
At cost		496.2	46.5	354.7	897.4
Accumulated depreciation		(91.8)	–	(72.6)	(164.4)
Carrying amount at end of financial year		404.4	46.5	282.1	733.0
Financial year ended 30 June 2023					
Balance at beginning of financial year		404.4	46.5	282.1	733.0
Additions	25(c)	63.0	127.9	–	190.9
Transfers from property, plant and equipment		12.0	–	–	12.0
Remeasurement of lease arrangements		–	–	(5.7)	(5.7)
Borrowing costs capitalised[(i)]		–	2.7	–	2.7
Depreciation expense		(85.5)	–	(57.5)	(143.0)
Net increase in provision for restoration[(ii)]	19(b)	8.8	–	–	8.8
Completions and transfers		177.1	(177.1)	–	–
Carrying amount at end of financial year		**579.8**	**–**	**218.9**	**798.7**
At 30 June 2023					
At cost		**757.1**	**–**	**349.0**	**1,106.1**
Accumulated depreciation		**(177.3)**	**–**	**(130.1)**	**(307.4)**
Carrying amount at end of financial year		**579.8**	**–**	**218.9**	**798.7**

(i) The capitalised borrowing costs relate to an apportionment of the fees incurred in connection with the syndicated loan facility (refer Note 21) relating to the Patola development, which met the definition of a qualifying asset.

(ii) Includes the addition of restoration obligations relating to the Patola wells, offset by an increase in the discount rate on total restoration provisions (refer Note 19).

NOTE 16. PROPERTY, PLANT AND EQUIPMENT

	NOTE	PLANT AND EQUIPMENT US$M	RIGHT OF USE ASSETS US$M	CONSOLIDATED TOTAL US$M
At 30 June 2022				
At cost		13.7	2.4	16.1
Accumulated depreciation		(1.8)	(1.0)	(2.8)
Carrying amount at end of financial year		11.9	1.4	13.3
Financial year ended 30 June 2023				
Balance at beginning of financial year		11.9	1.4	13.3
Additions	25(c)	2.7	–	2.7
Disposals		(0.5)	–	(0.5)
Transfer to Oil and Gas Assets		(12.0)	–	(12.0)
Depreciation expense		(0.4)	(0.4)	(0.8)
Carrying amount at end of financial year		**1.7**	**1.0**	**2.7**
At 30 June 2023				
At cost		**3.9**	**2.4**	**6.3**
Accumulated depreciation		**(2.2)**	**(1.4)**	**(3.6)**
Carrying amount at end of financial year		**1.7**	**1.0**	**2.7**

NOTE 17. EXPLORATION AND EVALUATION ASSETS

	NOTE	CONSOLIDATED 2023 US$M	CONSOLIDATED 2022 US$M
The reconciliation of exploration and evaluation expenditure carried forward is set out below:			
Balance at beginning of financial year		**40.9**	40.9
Additions	25(c)	**44.8**	1.4
Transfer to development assets		**–**	(1.4)
Total exploration and evaluation expenditure carried forward		**85.7**	40.9

NOTE 18. TRADE AND OTHER PAYABLES

	CONSOLIDATED 2023 US$M	CONSOLIDATED 2022 US$M
Current		
Trade payables	**47.8**	60.9
Sundry payables and accruals	**8.1**	5.3
Cash-settled share-based payments	**1.3**	2.1
Total current trade and other payables	**57.2**	68.3
Non-current (unsecured)		
Sundry payables and accruals	**5.8**	5.7
Cash-settled share-based payments	**–**	1.1
Total non-current trade and other payables	**5.8**	6.8

Financial Risk Management

Information concerning the Group's exposure to financial risks on trade and other payables is set out in Note 3.

NOTE 19. PROVISIONS

	CONSOLIDATED 2023 US$M	2022 US$M
Current		
Provision for long service leave (refer note (a) below)	**0.2**	0.4
Total current provision	**0.2**	0.4
Non-current		
Provision for restoration (refer note (b) below)	**153.3**	139.5
Total non-current provisions	**153.3**	139.5

(a) Provision for Long Service Leave

A provision was recognised for employee entitlements relating to long service leave. The measurement and recognition criteria relating to long service leave entitlements are as described in Note 1(t).

The current portion of this provision includes all the unconditional entitlements to long service leave where employees have completed the required period of service and also those where employees are entitled to pro-rata payments in certain circumstances.

(b) Reconciliation of provision for restoration

	CONSOLIDATED 2023 US$M	2022 US$M
Balance at beginning of financial year	**139.5**	158.7
Additions (refer note (i) below)	**23.8**	–
Discount unwinding on provision for restoration	**5.0**	2.4
Impact of increase in discount rate at year-end	**(15.0)**	(21.6)
Total provision for restoration	**153.3**	139.5

(i) A provision was recognised during the year for Brazilian restoration obligations relating to the Patola wells. The measurement and recognition criteria relating to restoration obligations are as described in Note 1(t).

(ii) A Parent Company guarantee totalling Brazilian REALS 117.7 million (US$24.4 million equivalent as at 30 June 2023) was provided to the ANP in respect of existing decommissioning obligations relating to the Baúna field.

NOTE 20. LEASES

	CONSOLIDATED	
	2023 US$M	2022 US$M
Current	**47.2**	43.7
Non-current	**200.4**	245.2
Total lease liabilities	**247.6**	288.9
Reconciliation		
Balance at beginning of financial year	**288.9**	312.8
Remeasurement of lease arrangements	**(5.7)**	20.8
Additions	**–**	0.9
Disposals	**–**	(0.2)
Adjustment to fixed lease payments	**(1.6)**	(0.8)
Accretion of interest	**15.5**	16.9
Payments	**(49.6)**	(61.4)
Net foreign currency differences	**0.1**	(0.1)
Total lease liabilities	**247.6**	288.9

NOTE 21. BORROWINGS

	CONSOLIDATED	
	2023 US$M	2022 US$M
Non-current		
Syndicated loan facility – secured	**30.0**	30.0
Less transaction costs[(i)]	**(1.9)**	(2.9)
Total non-current borrowings	**28.1**	27.1

(i) Includes remaining unamortised transaction costs associated with the syndicated loan facility and excludes costs that have been capitalised as part of Oil and Gas Assets in relation to qualifying assets.

During November 2021, Karoon Energy Ltd's wholly owned subsidiary, Karoon Petróleo & Gás Ltda, reached financial close on a new reserve-based, non-recourse, syndicated loan facility with Deutsche Bank AG, ING Belgium SA/NV, Macquarie Bank Limited and Shell Western Supply and Trading Limited. In April 2022, an additional accordion facility, contemplated by the syndicated loan facility, was established.

The facility is secured over the shares in and assets of Karoon Petróleo & Gás Ltda, including its interest in the Baúna BM-S-40 concession.

The total available amount under the facility, including the accordion, is $210 million. At 30 June 2023, $30 million has been drawn down, with $180m remaining undrawn.

Interest on drawn amounts is charged at SOFR, including a credit adjustment spread of 0.26%, plus a margin of 4.25% p.a. A commitment fee is charged on undrawn available amounts at 1.7% p.a. The facility has a final maturity date of the earlier of 31 March 2025 or the quarter where the remaining reserves are forecast to be ≤ 25% of the initial approved reserves. The availability period is anticipated to continue into the September quarter, but not longer than 30 September 2023, after which the unutilised commitments shall be cancelled. Contractual repayments are based on the total outstanding reduction schedule with the facility amortising semi-annually on a straight-line basis from 30 September 2023 to maturity.

Karoon is also required to enter into oil hedging to ensure forecasted oil production is within a minimum and maximum hedge ratio.

The Group has complied with all loan covenants throughout the reporting period.

NOTE 22. OTHER FINANCIAL ASSETS AND LIABILITIES

	CONSOLIDATED	
	2023 US$M	2022 US$M
Assets		
Current		
Derivative financial instruments – cash flow hedges(i)	**3.0**	–
Total assets	**3.0**	–
Liabilities		
Current		
Derivative financial instruments – cash flow hedges(i)	**–**	40.8
Embedded derivative – contingent consideration payable(ii)	**86.0**	84.6
Total current other financial liabilities	**86.0**	125.4
Non-current		
Derivative financial instruments – cash flow hedges(i)	**–**	8.3
Embedded derivative – contingent consideration payable(ii)	**133.0**	213.7
Total non-current other financial liabilities	**133.0**	222.0
Total other financial liabilities	**219.0**	347.4

(i) The Group has entered into Brent oil price derivative hedges, via a collar structure consisting of bought put and sold call options covering the period from December 2021 to March 2024. The purpose of the hedges is to protect operating cash flows from a portion of crude oil sales against the risk of lower oil prices while retaining significant exposure to oil price upside. The hedges are also a requirement of the syndicated loan facility (refer Note 21).

The bought put and sold call options have been designated as cash flow hedges, and in the current period, changes in the fair value of the options and costs of hedging of $52.2m pre-tax ($33.3m net of tax) have been recognised in the hedging reserves within equity (refer Note 23), which includes $2.0m pre-tax that has been reclassified to profit or loss. No losses were recognised in profit or loss for hedge ineffectiveness during the period.

At 30 June 2023, the Group had the following outstanding hedges:

FINANCIAL YEAR	BOUGHT PUT STRIKE (US$/BBL)	PUT VOLUME ('000 BBL)	SOLD CALL AVERAGE STRIKE (US$/BBL)	CALL VOLUME ('000 BBL)
2024	65	2,040	91.8	1,578
		2,040		**1,578**

(ii) Reconciliation of contingent consideration payable

	CONSOLIDATED	
	2023 US$M	2022 US$M
Balance at beginning of financial year	**298.3**	71.2
Payments	**(84.5)**	–
Unrealised fair value changes recognised in profit or loss during the period	**5.2**	227.1
Total contingent consideration payable at fair value	**219.0**	298.3

The contingent consideration arrangement for the acquisition of Baúna requires Karoon's wholly owned subsidiary, Karoon Petróleo & Gás Ltda., to pay Petrobras contingent consideration of up to US$285 million.

The contingent consideration accrues interest at 2% per annum from 1 January 2019 with any amounts payable by 31 January after the completion of the relevant testing period. The relevant testing periods are each calendar year from 2022 to 2026 inclusive and are based on the achievement of annual average Platts Dated Brent oil prices thresholds commencing at ≥US$50 and ending at ≥US$70 a barrel.

After the testing of each year, any amount deemed not payable is cancelled and not carried forward. The amount payable each calendar year excluding interest depending on achievement of certain oil prices is disclosed below:

AVERAGE BRENT PRICE (IN US$ UNITS)	CY2022	CY2023	CY2024	CY2025	CY2026	TOTAL
B < 50	–	–	–	–	–	–
50 <= B < 55	3	3	3	2	2	13
55 <= B < 60	17	17	17	8	4	63
60 <= B < 65	34	34	34	15	6	123
65 <= B < 70	53	53	53	24	10	193
B >= 70	78	78	78	36	15	285

As at 30 June 2022, based on the Group's internal assessment of future oil prices and industry consensus, the Brent oil forecast was revised and it was assessed that the amount payable under the contingent consideration arrangement would be the maximum amount payable of $285m plus interest.

At 30 June 2023, based on the Group's internal assessment of future oil prices and industry consensus, the amount payable continues to accrue at the maximum amount payable plus interest. $84.5m, the amount payable in respect of the 2022 calendar year, was paid in January 2023. The fair value of the total amount payable has been revised upwards by $5.2m due to a revision in the discount rate.

A discount rate of 3.42% and 2% interest per annum has been applied in the calculation of the present value at 30 June 2023. The fair value of the contingent consideration is estimated by calculating the present value of the future expected cash outflows.

NOTE 23. CONTRIBUTED EQUITY AND RESERVES WITHIN EQUITY

(a) Contributed Equity

	CONSOLIDATED		CONSOLIDATED	
	2023 NUMBER	2022 NUMBER	2023 US$M	2022 US$M
Ordinary shares, fully paid	**563,359,327**	558,085,352	**907.5**	907.5
Total contributed equity	**563,359,327**	558,085,352	**907.5**	907.5

Ordinary shares have no par value, and the Company does not have a limited amount of authorised capital.

Voting rights of shareholders are governed by the Company's Constitution. In summary, on a show of hands every holder of ordinary shares present at a meeting in person or by proxy is entitled to one vote, and on a poll each such attending shareholder is entitled to one vote for every fully paid ordinary share held.

Ordinary shares participate in dividends as declared from time to time and the proceeds on winding up of the Company in proportion to the number of fully paid ordinary shares held.

NOTE 23. CONTRIBUTED EQUITY AND RESERVES WITHIN EQUITY CONTINUED

(b) Movement in Ordinary Shares

DATE	DETAILS	NOTE	NUMBER OF ORDINARY SHARES	US$M
1 July 2021	Opening balance in previous financial year		553,770,529	905.1
	Exercise of options		2,383,899	2.4
	Performance rights conversion	29(a)	1,930,924	–
30 June 2022	Balance at end of financial year		558,085,352	907.5
	Performance rights conversion	29(a)	5,273,975	–
30 June 2023	Balance at end of financial year		**563,359,327**	**907.5**

(c) Capital Management

The Board of Directors controls the capital of the Company in order to ensure that the Group can fund its operations and continue as a going concern. The aim is to maintain a capital structure that ensures the lowest cost of capital to the Company.

The Chief Executive Officer and Managing Director manages the Company's capital by monitoring future rolling cash flows and adjusting its capital structure, as required, in consultation with the Board of Directors to meet Group business objectives. As required, the Group will balance its overall capital structure through the issue of new ordinary shares, share buy-backs and utilising short-term and long-term loan facilities when necessary.

There were no externally imposed capital management restrictions on the Group during the financial year.

(d) Reserves Within Equity

(i) Share-based Payments Reserve

The share-based payments reserve is used to recognise the grant date fair value of equity-settled share-based payments to Executive Directors, other key management personnel and employees as part of their remuneration, as described in Note 1(s).

(ii) Foreign Currency Translation Reserve

The foreign currency translation reserve is used to recognise exchange differences arising from the translation of financial statements into the presentation currency as described in Note 1(e). The relevant amounts included in the foreign currency translation reserve will be recognised in the consolidated statement of profit or loss and other comprehensive income when each relevant investment in the entity is disposed.

(iii) Hedging Reserves

During the prior year, the Group entered into Brent oil price derivative hedges. Refer to Note 22(i) for more details.

The Group designates only the change in fair value of the spot element of the derivative transaction contracts (the intrinsic value of the option) as the hedging instrument in cash flow hedging relationships. The change in fair value of the value of the option contract in time is separately accounted for as a cost of hedging and recognised in a cost of hedging reserve within equity.

The following is a reconciliation of the movement of the hedging reserves:

	COST OF HEDGING RESERVE US$M	INTRINSIC VALUE OF OPTIONS US$M	TOTAL HEDGING RESERVES US$M
Balance at beginning of financial year	39.4	(80.7)	(41.3)
Change in fair value of cash flow hedges and cost of hedging recognised in OCI	(70.0)	122.2	52.2
Reclassified from OCI to profit or loss – included in other expenses	(2.0)	–	(2.0)
Deferred tax	24.6	(41.5)	(16.9)
Balance at end of financial year	(8.0)	–	(8.0)

NOTE 24. SUBSIDIARIES

The consolidated financial statements incorporate the assets, liabilities and results of the following subsidiaries in accordance with the accounting policy described in Note 1(b):

NAME	COUNTRY OF INCORPORATION OR REGISTRATION	BUSINESS ACTIVITIES CARRIED ON IN	PERCENTAGE OF EQUITY AND VOTING INTERESTS HELD BY THE GROUP 2023 %	2022 %
Parent Company:				
Karoon Energy Ltd	Australia	Australia		
Unlisted subsidiaries of Karoon Energy Ltd:				
Karoon Energy International Pty Ltd	Australia	Australia	**100**	100
Karoon Gas Browse Basin Pty Ltd	Australia	Australia	**100**	100
Karoon Gas (FPSO) Pty Ltd	Australia	Australia	**100**	100
Unlisted subsidiaries of Karoon Energy International Pty Ltd:				
KEI (Brazil Santos) Pty Ltd	Australia	Australia	**100**	100
Karoon Peru Pty Ltd	Australia	Australia	**100**	100
KEI (Peru Z38) Pty Ltd	Australia	Australia	**100**	100
Unlisted subsidiary of KEI (Brazil Santos) Pty Ltd:				
Karoon Petróleo & Gás Ltda	Brazil	Brazil	**100**	100
Branch of KEI Peru Pty Ltd:				
Karoon Peru Pty Ltd, Sucursal del Peru	Peru	Peru	**100**	100
Branch of KEI (Peru Z38) Pty Ltd:				
KEI (Peru Z38) Pty Ltd, Sucursal del Peru	Peru	Peru	**100**	100

NOTE 25. SEGMENT INFORMATION

(a) Description of Segments

The Group has identified its operating segments based on the internal reports that are reviewed and used by the Group's Executive Management Team (identified as the 'chief operating decision maker') in assessing performance and in determining the allocation of resources.

The operating segments are based on the Group's geographical location of its operations.

The Group has identified operating segments based on the following two geographic locations:

- Australia – in which the Group was involved in the exploration and evaluation of hydrocarbons in an offshore exploration permit area: WA-482-P. This permit was surrendered in September 2022; and
- Brazil – in which the Group is currently involved in the exploration, development and production of hydrocarbons in four offshore blocks: Block BM-S-40, Block S-M-1037, Block S-M-1101, and Block S-M-1537.

'All other segments' include amounts of a corporate nature not specifically attributable to an operating segment. The comparative period included costs associated with the closure of the Group's Peruvian Branches.

The accounting policies of the reportable operating segments are the same as the Group's accounting policies.

Segment revenues and results do not include transfers between segments as intercompany balances are eliminated on consolidation.

Segment revenue is derived from an external customer who markets to a range of end customers.

Employee benefits expense and other expenses, which are associated with exploration and evaluation activities and specifically relate to an area of interest, are allocated to the area of interest and are either expensed or capitalised using the successful efforts method of accounting.

NOTE 25. SEGMENT INFORMATION CONTINUED

The amounts provided to the chief operating decision maker with respect to total assets and total liabilities are measured in a manner consistent with that of the consolidated financial statements. Reportable segment assets and segment liabilities are equal to consolidated total assets and total liabilities respectively. These assets and liabilities are allocated in accordance with the operations of the segment.

(b) Operating Segments

SEGMENT PERFORMANCE	AUSTRALIA US$M	BRAZIL US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Result for financial year ended 30 June 2023				
Revenue	–	566.5	–	566.5
Other income	0.4	5.3	–	5.7
Total segment revenue	0.4	571.8	–	572.2
Expenses				
Business development and transition costs	(1.5)	(2.2)	–	(3.7)
Cost of sales	–	(283.2)	–	(283.2)
Depreciation and amortisation expense				
– non-oil and gas assets	(0.3)	(0.6)	–	(0.9)
Exploration expenses	–	(3.9)	–	(3.9)
Finance costs	–	(25.4)	–	(25.4)
Realised losses on cash flow hedges	–	(7.1)	–	(7.1)
Social investments/sponsorships	–	(1.9)	–	(1.9)
Corporate expenses	(12.4)	(8.2)	(0.1)	(20.7)
Net foreign currency gains/(losses)	1.4	(2.2)	–	(0.8)
Change in fair value of contingent consideration	–	(5.2)	–	(5.2)
Share-based payments expense	(2.3)	(0.8)	–	(3.1)
Other	–	(0.1)	–	(0.1)
Profit/(loss) before income tax	(14.7)	231.0	(0.1)	216.2
Income tax (expense)/benefit	3.3	(56.5)	–	(53.2)
Profit/(loss) for financial year	(11.4)	174.5	(0.1)	163.0

SEGMENT PERFORMANCE	AUSTRALIA US$M	BRAZIL US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Result for financial year ended 30 June 2022				
Revenue	–	385.1	–	385.1
Other income	0.1	0.2	0.5	0.8
Total segment revenue	0.1	385.3	0.5	385.9
Expenses				
Business development and transition costs	(0.4)	(3.0)	–	(3.4)
Cost of sales	–	(191.7)	–	(191.7)
Depreciation and amortisation expense				
– non-oil and gas assets	(0.3)	(0.4)	–	(0.7)
Exploration expenses	(0.3)	(2.8)	(0.1)	(3.2)
Finance costs	–	(22.7)	–	(22.7)
Realised losses on cash flow hedges	–	(11.8)	–	(11.8)
Corporate expenses	(10.9)	(3.6)	(0.9)	(15.4)
Net foreign currency gains/(losses)	4.6	2.1	(0.5)	6.2
Change in fair value of contingent consideration	–	(227.1)	–	(227.1)
Share-based payments expense	(3.7)	(2.0)	–	(5.7)
Other	–	(0.1)	(0.1)	(0.2)
Profit/(loss) before income tax	(10.9)	(77.8)	(1.1)	(89.8)
Income tax benefit	2.4	23.0	–	25.4
Profit/(loss) for financial year	(8.5)	(54.8)	(1.1)	(64.4)

FINANCIAL YEAR ENDED 30 JUNE 2023	AUSTRALIA US$M	BRAZIL US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Total segment assets	**29.3**	**1,161.1**	**–**	**1,190.4**
Total segment liabilities	**1.1**	**715.7**	**–**	**716.8**

FINANCIAL YEAR ENDED 30 JUNE 2022	AUSTRALIA US$M	BRAZIL US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Total segment assets	49.3	1,114.7	0.2	1,164.2
Total segment liabilities	4.8	883.1	0.1	888.0

NOTE 25. SEGMENT INFORMATION CONTINUED

(c) Other Segment Information

Additions to non-current assets, other than financial assets (refer Note 3), during the reporting periods were:

FINANCIAL YEAR ENDED 30 JUNE 2023	AUSTRALIA US$M	BRAZIL US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Property, plant and equipment^	**0.2**	**2.5**	**–**	**2.7**
Exploration and evaluation assets	**–**	**44.8**	**–**	**44.8**
Oil and gas assets	**–**	**190.9**	**–**	**190.9**

^ Includes right-of-use assets.

FINANCIAL YEAR ENDED 30 JUNE 2022	AUSTRALIA US$M	BRAZIL US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Property, plant and equipment^	0.2	5.7	–	5.9
Oil and gas assets	–	92.0	–	92.0

^ Includes right-of-use assets.

NOTE 26. CONTINGENT LIABILITIES AND CONTINGENT ASSETS

(a) Contingent Liabilities

The Group has contingent liabilities as at 30 June 2023 that may become payable in respect of:

	CONSOLIDATED 2023 US$M	CONSOLIDATED 2022 US$M
(i) The Group has provided the ANP a letter of credit (refer Note 13) to carry out the minimum work program in relation to exploration in Santos Basin Block S-M-1537. The Directors are of the opinion that the work program commitments will be satisfied. The letter of credit is fully funded by way of payment of a security deposit, which will be released once the work program is met.	**2.1**	1.2
(ii) Bank guarantees were provided in respect of rental agreements for office premises of the Group. These guarantees may give rise to liabilities in the Group if obligations are not met under these guarantees. The bank guarantees given to lessors are fully funded by way of payment of security deposits (refer Note 13).	**0.2**	0. 1
(iii) Cash deposits (refer Note 13) are held as bonds for the Group's compliance with its obligations in respect of agreements for the guarantee of payment obligations for various accommodation in Brazil.	**0.4**	0.3

(iv) Block Acquisition

As part of the acquisition of Pacific Exploration and Production Corp's equity interest of Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102, S-M-1165 and S-M-1166 during the 2017 financial year, the Group agreed to pay Pacific Exploration and Production Corp. a deferred contingent consideration of $5.0 million payable on first production reaching a minimum of 1 million barrels of oil equivalent from the Blocks. The deferred contingent obligation has not been provided for as at 30 June 2023, as it is dependent on uncertain future events.

(v) Brazilian Local Content

The Concession Contracts for Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102, S-M-1165, S-M-1537 and S-M-1166 require Karoon Petróleo & Gás Ltda to acquire a minimum proportion of goods and services from Brazilian suppliers, with the objective to stimulate industrial development, promote and diversify the Brazilian economy, encourage advanced technology and develop local capabilities. The minimum Brazilian local content requirement under the Concession Contracts during the exploration and appraisal phase is up to 55%. If Karoon Petróleo & Gás Ltda fails to comply with this minimum requirement, Karoon Petróleo & Gás Ltda may be subject to a fine by the ANP.

(vi) Joint Operations

In accordance with normal industry practice, the Group has entered into joint operations with other parties for the purpose of exploring and evaluating its exploration tenements. If a participant to a joint operation defaults and does not contribute its share of joint operation obligations, then the remaining joint operation participants are jointly and severally liable to meet the obligations of the defaulting participant. In this event, the equity interest in the exploration tenements held by the defaulting participant may be redistributed to the remaining joint operation participants.

In the event of a default, a contingent liability exists in respect of expenditure commitments due to be met by the Group in respect of the defaulting joint operation participant.

(vii) Other Matters

There are also legal claims and exposures, which arise from the Group's ordinary course of business. No material loss to the Group is expected to result.

(b) Contingent Assets

The Group has no contingent assets as at 30 June 2023 (30 June 2022: $Nil).

NOTE 27. COMMITMENTS

	CONSOLIDATED	
	2023 US$M	2022 US$M
(a) Capital and Service Expenditure Commitments		
Contracts for capital and service expenditure in relation to assets not provided for in the consolidated financial statements and payable.		
Capital commitments		
Not later than one year	**4.4**	75.9
Later than one year but not later than five years	**–**	–
Total capital commitments	**4.4**	75.9
Service commitments		
Not later than one year	**14.1**	11.5
Later than one year but not later than five years	**22.2**	31.9
Total service commitments	**36.3**	43.4
Total capital and service expenditure commitments	**40.7**	119.3
(b) Exploration Expenditure Commitments		
The Group has guaranteed commitments for exploration expenditure arising from obligations to governments to perform minimum exploration and evaluation work and expend minimum amounts of money pursuant to the award of exploration tenement Block S-M-1537 (30 June 2022: Block S-M-1537) not provided for in the consolidated financial statements and payable.		
Later than one year but not later than five years	**3.5**	3.5
Total guaranteed exploration expenditure commitments	**3.5**	3.5

Note, the figures above do not include any commitments in relation to Exploration Blocks S-M-1037 and S-M-1101 relating to the Neon and Goiá light oil discoveries. In accordance with Brazilian regulatory requirements, during January 2019 Karoon submitted both a Final Discovery Evaluation Report and Declaration of Commerciality for the discoveries. This transitioned the Blocks for Brazilian regulatory requirements, from the exploration phase to the development phase. However, it does not mean that Karoon has reached, nor is compelled to reach, a final investment decision ('FID') to proceed into a Development of the discoveries.

Estimates for future exploration expenditure commitments to government are based on estimated well and seismic costs, which will change as actual drilling locations and seismic surveys are completed and are calculated in current dollars on an undiscounted basis. The exploration and evaluation obligations may vary significantly as a result of renegotiations with relevant parties. The commitments may also be reduced by the Group entering into farm-out agreements, which are typical of the normal operating activities of the Group, or by relinquishing exploration tenements.

NOTE 28. RECONCILIATION TO THE CONSOLIDATED STATEMENT OF CASH FLOWS

(a) Reconciliation of Profit/(Loss) for Financial Year to Net Cash Flows Used in Operating Activities

	CONSOLIDATED	
	2023 US$M	2022 US$M
Profit/(loss) for financial year	**163.0**	(64.4)
Add (subtract)		
Non-cash items included in profit/(loss) for financial year:		
Depreciation and amortisation	**143.8**	100.1
Amortisation of finance costs	**1.1**	0.5
Change in fair value of derivative financial instruments	**50.2**	(62.5)
Change in fair value of contingent consideration	**5.2**	227.1
Discount unwinding on provision for restoration and deferred consideration	**5.0**	2.4
Share-based payments expense	**2.6**	3.6
Gain on disposal of right-of-use asset	**–**	(0.1)
Net foreign currency losses (gains)	**(3.0)**	(3.0)
Loss on disposal of non-current assets	**0.1**	
Write-back of inventory impaired	**(1.6)**	–
Items classified as investing/financing activities:		
Interest paid on deferred consideration	**–**	1.2
Net (gain) loss on disposal of non-current assets	**–**	(0.5)
Net foreign currency gains (losses)	**0.6**	(0.5)
Change in operating assets and liabilities:		
(Increase)/decrease in assets		
Receivables – current	**(14.7)**	(22.2)
Oil Inventories	**11.5**	(6.4)
Deferred tax assets	**(1.7)**	(86.5)
Other financial assets – derivative financial instruments	**(3.0)**	–
Other assets	**2.4**	(6.9)
Increase/(decrease) in liabilities		
Trade and other payables – current	**15.6**	0.1
Trade and other payables – non-current	**(1.0)**	2.5
Provisions – current	**(0.2)**	(0.1)
Current tax liabilities	**(4.0)**	1.3
Deferred tax liabilities	**(16.9)**	19.4
Other financial liabilities – derivative financial instruments	**(49.1)**	49.1
Net cash flows provided by (used in) operating activities	**305.9**	154.2

NOTE 29. SHARE-BASED PAYMENTS

The share-based payment plans are described below. There has been no cancellation to a plan during the financial year.

(a) Performance Rights Plan ('PRP')

The Company currently has two PRPs in place, the 2019 PRP and 2022 PRP. The 2022 PRP was approved by shareholders at the 2022 Annual General Meeting.

Under the PRP, eligible employees are offered performance rights, which subject to performance conditions, can on exercise be converted to fully paid ordinary shares in the Company, or equivalent cash value, for no consideration provided certain conditions have been met. Vesting of STI performance rights is conditional on the achievement of performance measures, over a one-year performance period, and provided the employee remains employed by the Company for an additional year. Vesting of LTI performance rights is conditional on the achievement of performance measures over a three-year performance period. In each case, the Board, on advice from the People and Culture Committee, will be responsible for assessing whether the performance measures have been achieved. When vested, each performance right is, subject to exercise, convertible into one ordinary share of the Company.

Performance rights granted carry no dividend or voting rights.

If there is a change of control of the Company, for all unexercised performance rights issued pursuant to the Company's PRP, a percentage amount of unvested performance rights may vest on the basis of the pro-rata achievement of pre-determined performance conditions.

During the financial year, the Group granted 495,468 performance rights (2022: 577,052) over unissued ordinary shares in the Company to the Chief Executive Officer and Managing Director. The performance rights were provided to the Chief Executive Officer and Managing Director and were subject to approval by shareholders at the 2022 Annual General Meeting. An additional 12,649 performance rights associated with the 2023 Long Term Incentive are subject to shareholder approval at the 2023 Annual General Meeting. Performance rights issued to Directors are approved on a case-by-case basis by shareholders at relevant general meetings.

The following summary reconciles the outstanding performance rights over unissued ordinary shares in the Company at the beginning and end of the financial year:

	CONSOLIDATED	
	2023 NUMBER	2022 NUMBER
Balance at beginning of financial year	**13,645,295**	14,861,486
Granted during financial year(i)	**2,813,925**	2,370,032
Vested and converted during financial year(ii)	**(5,273,975)**	(1,930,924)
Cash-settled during financial year	**(1,326,032)**	(363,452)
Forfeited during financial year	**(796,145)**	(1,291,847)
Balance at end of financial year	**9,063,068**	13,645,295

(i) The weighted average fair value of performance rights granted during the financial year was A$1.68 (2022: A$1.66). Fair values of STI performance rights were based on the Company's closing share price at grant date whereas LTI performance rights were based on a Monte Carlo simulation valuation at grant date. Refer to details at Note 29(b) below.

(ii) The weighted average exercise price of performance rights converted during the financial year was A$Nil (2022: A:$Nil).

Performance rights issued during the financial year were issued under the 2022 PRP.

NOTE 29. SHARE-BASED PAYMENTS CONTINUED

Performance rights outstanding as at 30 June 2023 had a weighted average remaining contractual life of 635 days (30 June 2022: 617 days). Details of performance rights outstanding at the end of the financial year are:

GRANT DATE	DATE OF EXPIRY	NUMBER
25 September 2020	30 June 2024	**3,677,954**
26 November 2021	30 June 2024	**502,989**
23 March 2022	30 June 2025	**928,327**
6 May 2022	30 June 2025	**1,246,439**
24 November 2022	30 June 2024	**62,891**
24 November 2022	30 June 2026	**432,577**
16 December 2022	30 June 2024	**379,360**
16 December 2022	30 June 2026	**1,726,970**
31 March 2023	30 June 2026	**105,561**
Total performance rights		**9,063,068**

(b) Fair Value of Performance Rights

The fair value of each LTI performance right issued during the financial year was estimated on grant date using the Monte Carlo valuation methodology. The Monte Carlo valuation methodology takes into account the exercise price, the term of the performance right, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the performance right. The fair value of STI performance rights issued during the current or previous financial years were based on the Company's closing share price at grant date.

The Group applied the following assumptions and inputs in estimating the weighted average fair value for LTI performance rights:

	2023	2022
Weighted average exercise price	**$A Nil**	$A Nil
Weighted average life of performance rights	**1,172 days**	1,172 days
Weighted average share price	**A$2.18**	A$2.12
Expected share price volatility	**48.40%**	60.00%
Risk free interest rate	**3.70%**	2.17%
Dividend yield	**1.39%**	–
Weighted average performance rights value	**A$1.58**	A$1.66

Historical volatility was the basis for determining expected share price volatility as it is assumed that this is indicative of future trends, which may not eventuate.

(c) Share-based Payments Expense

Total expenses arising from share-based payment transactions recognised during the financial year, included as part of other expenses in the consolidated statement of profit or loss and other comprehensive income, were as follows:

	CONSOLIDATED	
	2023 US$M	2022 US$M
Performance rights issued under PRP	**2.6**	3.6
Share-based payments expense (non-cash)	**2.6**	3.6
Share-based payments expense (cash-settled)	**0.5**	2.1
Total share-based payments expense	**3.1**	5.7

NOTE 30. RELATED PARTY TRANSACTIONS

Transactions between related parties are on normal commercial terms and conditions, no more favourable than those available to other parties, unless otherwise stated.

(a) Subsidiaries

Interests in subsidiaries are set out in Note 24.

During the financial year, the Parent Company provided accounting, administrative and technical services to subsidiaries at cost or at cost plus a mark-up where required under relevant tax transfer pricing legislation. This allocation was based on costs recharged on a relevant time allocation of employees and consultants and associated office charges.

Other transactions that occurred were provision of funding by the Parent Company to its overseas subsidiaries via an increase in contributed equity and intercompany loans to the Australian subsidiaries. The intercompany loans provided are at a Nil% interest rate (2022: Nil%) and no fixed term for repayment and therefore will not be repaid within 12 months. Loans are unsecured and are repayable in cash.

Where equity-settled performance rights are issued to employees of subsidiaries within the Group, the transaction is recognised as an investment in the subsidiary by the Parent Company and in the subsidiary, a share-based payments expense and an equity contribution by the Parent Company.

The above transactions are eliminated on consolidation.

(b) Remuneration of Key Management Personnel

Directors and other key management personnel remuneration is summarised as follows:

	CONSOLIDATED	
	2023 US$000	2022 US$000
Short-term employee benefits	**2,380**	2,771
Post-employment benefits	**197**	221
Long-term employee benefits (non-cash)	**59**	4
Termination benefits	**–**	436
Share-based payments expense	**1,193**	2,307
Total key management personnel remuneration	**3,829**	5,739

Detailed remuneration disclosures for the Directors and other key management personnel are provided in Section 5 of the audited Remuneration Report on pages 60 to 66. Termination of the Executive Director's and other key management personnel's employment is subject to a minimum notice period as disclosed on page 58 of the audited Remuneration Report.

Apart from the details disclosed in this note, no Director or other key management personnel has entered into a material contract with the Group since the end of the previous financial year and there were no material contracts involving Directors' or other key management personnel interests subsisting as at 30 June 2023.

NOTE 30. RELATED PARTY TRANSACTIONS CONTINUED

(c) Other Transactions with Directors and Other KMP

During the financial year, Mr Tadeu Fraga, a Non-Executive Director, had an interest in Radix Engenharia e Software (Radix), that provided engineering consulting services to the Group at market prices. The contract value for these services from Mr Fraga's appointment on 26 August 2022 to 30 June 2023 was US$171,190. Mr Fraga's interest in Radix commenced on 1 March 2023, post the execution of the contract.

During the financial year, Ms Carolina Fraga, a family member of Mr Tadeu Fraga, a Non-Executive Director, who was appointed on 26 August 2022, remained employed by the Group as HR Co-ordinator in Brazil. The total value of her remuneration (including share-based payments expense) from 26 August 2022 to 30 June 2023 was US$89,841. Ms Fraga has been an employee of the Group since 2021. Ms Fraga's employment with the Karoon group commenced prior to the appointment of the relevant Non-Executive Director.

NOTE 31. PARENT COMPANY FINANCIAL INFORMATION

(a) Summary Financial Information

The individual financial statements for the Parent Company show the following aggregate amounts:

	CONSOLIDATED	
	2023 US$M	2022 US$M
Statement of financial position		
Current assets	**32.8**	47.6
Non-current assets	**168.9**	169.8
Total assets	**201.7**	217.4
Current liabilities	**4.7**	3.9
Non-current liabilities	**0.2**	1.0
Total liabilities	**4.9**	4.9
Net assets	**196.8**	212.5
Contributed equity	**907.5**	907.5
Accumulated losses	**(663.9)**	(653.4)
Share-based payments reserve	**56.4**	53.8
Foreign currency translation reserve	**(103.2)**	(95.4)
Total equity	**196.8**	212.5
Profit/(Loss) for financial year	**(10.5)**	(78.6)
Total comprehensive Income/(loss) for financial year	**(15.7)**	(100.8)
(b) Contingent Liabilities of Parent Company		
(i) Bank guarantees were provided in respect of lease rental agreements. These guarantees may give rise to liabilities in the Parent Company if obligations are not met under these guarantees. The bank guarantees given to lessors are fully funded by way of payment of security deposits (refer Note 13).	0.2	0.1
(ii) The Company's present intention is to provide the necessary financial support for all Australian incorporated subsidiaries, whilst they remain wholly owned subsidiaries, as is necessary for each company to pay all debts as and when they become due.		

(c) Guarantees Entered into by Parent Company

A Parent Company guarantee was provided to Petrobras for payment of all amounts that may become payable under the SPA.

A Parent Company guarantee totalling Brazilian REALS 117.7 million (US$24.4 million equivalent as at 30 June 2023) was provided to the ANP in respect of existing decommissioning obligations relating to the Baúna field. In addition, the Parent has provided deeds of guarantee to, respectively, OOG-TKP FPSO GMBH & CO KG (the FPSO operator) and OOG-TKP Produção de Petróleo Ltda (the FPSO service provider) in relation to satisfying Karoon Petróleo & Gás Ltda's payment obligations in respect of the charter of an FPSO for Baúna and the provision of related services.

Parent Company guarantees have been provided to the ANP guaranteeing a subsidiary's obligations under Concession Agreements covering Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102 and S-M-1537 in Brazil.

NOTE 32. SUBSEQUENT EVENTS

This Annual Report was authorised for issue by the Board of Directors on 23 August 2023. The Board of Directors has the power to amend and reissue the consolidated financial statements and notes.

Since 30 June 2023, there have been no material events that have occurred.

DIRECTORS' DECLARATION

The Directors' declare that:

(a) in the Directors' opinion, the consolidated financial statements and notes, set out on pages 69 to 115. are in accordance with the *Corporations Act 2001*, including:

(i) complying with relevant Australian Accounting Standards and the *Corporations Regulations 2001;*

and

(ii) giving a true and fair view of the Group's financial position as at 30 June 2023 and of its performance for the financial year ended on that date; and

(b) in the Directors' opinion, there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

Note 1(a) confirms that the consolidated financial statements also comply with International Financial Reporting Standards as issued by the International Accounting Standards Board.

The Directors have been given the declarations by the Chief Executive Officer and Managing Director, and Executive Vice President and Chief Financial Officer required by Section 295A of the *Corporations Act 2001*.

This Directors' Declaration is made in accordance with a resolution of the Directors.

On behalf of the Directors:

Mr Bruce Phillips
Independent Non-Executive Chairman

Dr Julian Fowles
Chief Executive Officer and Managing Director

23 August 2023

Independent auditor's report

To the members of Karoon Energy Ltd

Report on the audit of the financial report

Our opinion

In our opinion:

The accompanying financial report of Karoon Energy Ltd (the Company) and its controlled entities (together the Group) is in accordance with the *Corporations Act 2001*, including:

(a) giving a true and fair view of the Group's financial position as at 30 June 2023 and of its financial performance for the year then ended

(b) complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

What we have audited

The Group financial report comprises:

- the consolidated statement of financial position as at 30 June 2023
- the consolidated statement of profit or loss and other comprehensive income for the year then ended
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows for the year then ended
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information
- the directors' declaration.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional & Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

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Our audit approach

An audit is designed to provide reasonable assurance about whether the financial report is free from material misstatement. Misstatements may arise due to fraud or error. They are considered material if individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

We tailored the scope of our audit to ensure that we performed enough work to be able to give an opinion on the financial report as a whole, taking into account the geographic and management structure of the Group, its accounting processes and controls and the industry in which it operates.

Materiality

- For the purpose of our audit, we used overall Group materiality of US$10.8 million, which represents approximately 5% of the Group's profit before tax.
- We applied this threshold, together with qualitative considerations, to determine the scope of our audit and the nature, timing and extent of our audit procedures and to evaluate the effect of misstatements on the financial report as a whole.
- We chose Group profit before tax because, in our view, it is the benchmark against which the performance of the Group is most commonly measured.
- We utilised a 5% threshold based on our professional judgement, noting it is within the range of commonly acceptable thresholds.

Audit Scope

- Our audit focused on where the Group made subjective judgements, for example, significant accounting estimates involving assumptions and inherently uncertain future events.
- In establishing the overall approach to the Group audit, we determined the type of work that needed to be performed by us, as the Group engagement team, and by component auditors under our instruction.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report for the current period. The key audit matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. Further, any commentary on the outcomes of a particular audit procedure is made in that context. We communicated the key audit matters to the Audit, Risk and Governance Committee.

Key audit matter	How our audit addressed the key audit matter
***Assessing the carrying value of oil and gas assets** (Refer to note 15)*	
As at 30 June 2023, the Group's consolidated statement of financial position includes oil and gas assets of US$798.7 million. Group policy is to assess for indicators of impairment annually or more frequently if indicators of impairment exist. Assessing the carrying value of oil and gas assets was a key audit matter because of the judgement involved in the Group assessing impairment indicators and the financial significance of oil and gas assets.	To assess the carrying value of oil and gas assets, we performed the following procedures, amongst others: • Evaluated the Group's assessment of whether there were any indicators of asset impairment, including consideration of movement in oil prices, reserves and resources and asset performance over the year. • Compared the value of the net assets of the Group at year end to the market capitalisation.

Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report for the year ended 30 June 2023, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and accordingly we do not express any form of assurance conclusion thereon through our opinion on the financial report. We have issued a separate opinion on the remuneration report and a limited assurance conclusion on selected sustainability information in page 28 of the annual report for the year ended 30 June 2023.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

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Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website at:
https://www.auasb.gov.au/admin/file/content102/c3/ar1_2020.pdf. This description forms part of our auditor's report.

Report on the remuneration report

Our opinion on the remuneration report

We have audited the remuneration report included in pages 47 to 66 of the directors' report for the year ended 30 June 2023.

In our opinion, the remuneration report of Karoon Energy Ltd for the year ended 30 June 2023 complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the remuneration report in accordance with section 300A of *the Corporations Act 2001*. Our responsibility is to express an opinion on the remuneration report, based on our audit conducted in accordance with Australian Auditing Standards.

PricewaterhouseCoopers

PricewaterhouseCoopers

Graeme McKenna

Graeme McKenna
Partner

Melbourne
23 August 2023

AUDITOR'S INDEPENDENCE DECLARATION

Auditor's Independence Declaration

As lead auditor for the review of Karoon Energy Ltd for the half-year ended 31 December 2022, I declare that to the best of my knowledge and belief, there have been:

(a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the review; and

(b) no contraventions of any applicable code of professional conduct in relation to the review.

This declaration is in respect of Karoon Energy Ltd and the entities it controlled during the period.

Graeme McKenna
Partner
PricewaterhouseCoopers

Melbourne
22 February 2023

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CONDENSED CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

	NOTE	CONSOLIDATED 31 DEC 2022 US$M	31 DEC 2021 US$M
Revenue	3(a)	**299.4**	186.5
Cost of sales	4(a)	**(148.3)**	(104.4)
Gross profit		**151.1**	82.1
Other income	3(b)	**1.1**	0.1
Business development and other project costs	4(b)	**(1.5)**	(0.9)
Exploration expenses	4(c)	**(1.7)**	(1.7)
Finance costs	4(d)	**(11.7)**	(11.0)
Other expenses	4(e)	**(20.8)**	(12.2)
Net foreign currency gains		**0.3**	3.4
Change in fair value of contingent consideration		**(0.4)**	(183.8)
Profit/(loss) before income tax		**116.4**	(124.0)
Income tax (expense)/benefit	5	**(38.8)**	26.3
Profit/(loss) for the period attributable to equity holders of the Company		**77.6**	(97.7)
Other comprehensive income (loss), net of income tax:			
Items that may be reclassified subsequently to profit or loss			
Exchange differences arising from the translation of financial statements into presentation currency		**(0.8)**	(1.9)
Net change in cost of hedging		**24.5**	(3.5)
Other comprehensive income (loss) for the period, net of income tax		**23.7**	(5.4)
Total comprehensive income (loss) for the period attributable to equity holders of the Company, net of income tax		**101.3**	(103.1)
Earnings/(loss) per share attributable to equity holders of the Company:			
Basic earnings/(loss) per ordinary share (cents per share)		**13.82**	(17.62)
Diluted earnings/(loss) per ordinary share (cents per share)		**13.64**	(17.62)

The accompanying notes form an integral part of these condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENT OF FINANCIAL POSITION

AS AT 31 DECEMBER 2022

	NOTE	CONSOLIDATED 31 DEC 2022 US$M	30 JUNE 2022 US$M
Current assets			
Cash and cash equivalents		**163.2**	157.7
Receivables		**79.3**	56.4
Inventories		**14.8**	19.4
Security deposits		**–**	0.3
Other assets		**7.3**	11.8
Total current assets		**264.6**	245.6
Non-current assets			
Deferred tax assets	5	**125.3**	123.0
Inventories		**4.5**	5.8
Oil and gas assets	7	**813.2**	733.0
Property, plant and equipment	8	**2.9**	13.3
Exploration and evaluation assets		**41.3**	40.9
Security deposits		**2.4**	1.3
Other financial assets	10	**1.4**	–
Other assets		**1.2**	1.3
Total non-current assets		**992.2**	918.6
Total assets		**1,256.8**	1,164.2
Current liabilities			
Trade and other payables		**70.2**	68.3
Current tax liabilities		**44.8**	9.6
Other financial liabilities	10	**96.1**	125.4
Lease liabilities		**45.2**	43.7
Provisions		**0.2**	0.4
Total current liabilities		**256.5**	247.4
Non-current liabilities			
Trade and other payables		**5.6**	6.8
Borrowings	9	**27.6**	27.1
Other financial liabilities	10	**214.1**	222.0
Lease liabilities		**222.0**	245.2
Provisions		**151.9**	139.5
Total non-current liabilities		**621.2**	640.6
Total liabilities		**877.7**	888.0
Net assets		**379.1**	276.2
Equity			
Contributed equity	11	**907.5**	907.5
Accumulated losses		**(401.2)**	(478.8)
Reserves		**(127.2)**	(152.5)
Total equity		**379.1**	276.2

The accompanying notes form an integral part of these condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

CONSOLIDATED	CONTRIBUTED EQUITY US$M	ACCUMULATED LOSSES US$M	SHARE-BASED PAYMENTS RESERVE US$M	FOREIGN CURRENCY TRANSLATION RESERVE US$M	HEDGING RESERVES US$M	TOTAL EQUITY US$M
Balance as at 1 July 2021	905.1	(414.4)	50.2	(160.7)	–	380.2
Loss for the period	–	(97.7)	–	–	–	(97.7)
Other comprehensive loss	–	–	–	(1.9)	(3.5)	(5.4)
Total comprehensive loss for the period	–	(97.7)	–	(1.9)	(3.5)	(103.1)
Transactions with owners in their capacity as owners:						
Exercise of options	0.9	–	–	–	–	0.9
Share-based payments expense	–	–	2.4	–	–	2.4
	0.9	–	2.4	–	–	3.3
Balance as at 31 December 2021	906.0	(512.1)	52.6	(162.6)	(3.5)	280.4
Balance as at 1 July 2022	**907.5**	**(478.8)**	**53.8**	**(165.0)**	**(41.3)**	**276.2**
Profit for the period	**–**	**77.6**	**–**	**–**	**–**	**77.6**
Other comprehensive income/(loss)	**–**	**–**	**–**	**(0.8)**	**24.5**	**23.7**
Total comprehensive income/(loss) for the period	**–**	**77.6**	**–**	**(0.8)**	**24.5**	**101.3**
Transactions with owners in their capacity as owners:						
Share-based payments expense	**–**	**–**	**1.6**	**–**	**–**	**1.6**
	–	**–**	**1.6**	**–**	**–**	**1.6**
Balance as at 31 December 2022	**907.5**	**(401.2)**	**55.4**	**(165.8)**	**(16.8)**	**379.1**

The accompanying notes form an integral part of these condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

	CONSOLIDATED 31 DEC 2022 US$M	 31 DEC 2021 US$M
Cash flows from operating activities		
Receipts from customers	**276.7**	184.5
Payments to suppliers and employees	**(66.8)**	(57.8)
Payments for exploration and evaluation expenditure expensed	**(1.3)**	(2.1)
Payments for legal settlement	**–**	(9.6)
Payments for cash flow hedges	**(12.7)**	(9.8)
Interest received	**1.4**	–
Borrowing and other costs of finance paid	**(9.3)**	(9.6)
Income taxes paid	**(20.9)**	(11.7)
Net cash flows provided by operating activities	**167.1**	83.9
Cash flows from investing activities		
Purchase of plant and equipment and computer software	**(2.3)**	(2.2)
Payments for oil and gas assets	**(137.1)**	(11.9)
Borrowing costs paid for qualifying assets	**(1.7)**	(4.2)
Payments for exploration and evaluation expenditure capitalised	**(0.5)**	–
Release/refund (payment) of security deposits	**(0.8)**	–
Net cash flows used in investing activities	**(142.4)**	(18.3)
Cash flows from financing activities		
Proceeds from issue of ordinary shares	**–**	0.9
Proceeds from borrowings	**–**	30.0
Debt facility establishment costs	**–**	(2.2)
Principal elements of lease payments	**(19.7)**	(23.3)
Net cash flows provided by/(used in) financing activities	**(19.7)**	5.4
Net increase in cash and cash equivalents	**5.0**	71.0
Cash and cash equivalents at beginning of the half-year	**157.7**	133.2
Effect of exchange rate changes on the balance of cash and cash equivalents held in foreign currencies	**0.5**	(0.1)
Cash and cash equivalents at end of the half-year	**163.2**	204.1

The accompanying notes form an integral part of these condensed consolidated financial statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Basis of Preparation of the Condensed Consolidated Financial Statements

(a) Basis of Preparation

This Half-Year Financial Report is a general purpose financial report, which has been prepared in accordance with Australian Accounting Standard AASB 134 '*Interim Financial Reporting*' and the *Corporations Act 2001*. Compliance with AASB 134 '*Interim Financial Reporting*' ensures compliance with International Financial Reporting Standard IAS 134 '*Interim Financial Reporting*'.

The condensed consolidated financial statements are for the consolidated entity comprising Karoon Energy Ltd (the 'Company') and its subsidiaries (the 'Group') for the half-year period ended 31 December 2022. The Company is a for-profit entity limited by shares incorporated in Australia whose shares are publicly traded on the Australian Securities Exchange (ASX:KAR).

The condensed consolidated financial statements do not include all the notes of the type normally included in an Annual Report and should be read in conjunction with the Company's Annual Report for the financial year ended 30 June 2022 and any public announcements made by Karoon Energy Ltd during the interim reporting period in accordance with the continuous disclosure requirements of the ASX Listing Rules and the *Corporations Act 2001*.

The condensed consolidated financial statements have been prepared using the going concern assumption which contemplates the realisation of assets and settlement of liabilities in the ordinary course of business.

The condensed consolidated financial statements have been prepared using the same accounting policies and methods of computation as disclosed in the Company's Annual Report for the financial year ended 30 June 2022.

(b) Rounding

The amounts in the financial statements are rounded to the nearest hundred thousand dollars unless otherwise indicated, under the option available to the Company under *ASIC Corporation (Rounding in Financial/Directors' Report) Instrument 2016/191*. The Company is an entity to which this legislative instrument applies.

(c) New and amended standards adopted by the Group

A number of amended standards became applicable for the current reporting period. The Group did not have to change its accounting policies or make retrospective adjustments as a result of adopting these amended standards.

Note 2. Significant Accounting Estimates, Assumptions and Judgements

The preparation of the half-year financial report requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amount of assets and liabilities, income and expense. Actual results may differ from these estimates.

The significant accounting judgements, estimates and assumptions adopted in this half-year financial report are consistent with those disclosed in the Company's Annual Report for the financial year ended 30 June 2022.

Note 3. Revenue and Other Income

	CONSOLIDATED HALF-YEAR ENDED	
	31 DEC 2022 US$M	31 DEC 2021 US$M
(a) Revenue		
Crude oil sales	**299.4**	186.5
Total revenue from contracts with customers	**299.4**	186.5
(b) Other income		
Interest income	**1.1**	0.1
Total other income	**1.1**	0.1

Note 4. Expenses

	CONSOLIDATED HALF-YEAR ENDED	
	31 DEC 2022 US$M	31 DEC 2021 US$M
(a) Cost of sales		
Operating costs	**(30.3)**	(26.8)
Royalties and government take	**(30.3)**	(19.1)
Depreciation and amortisation – oil and gas assets	**(81.7)**	(53.2)
Change in inventories	**(6.0)**	(5.3)
Total cost of sales	**(148.3)**	(104.4)
(b) Business development and other project costs		
Business development and other project costs	**(1.5)**	(0.9)
Total business development and other project costs	**(1.5)**	(0.9)
(c) Exploration expense		
Exploration and evaluation expenditure expensed	**(1.7)**	(1.7)
Total exploration and evaluation expenditure expensed	**(1.7)**	(1.7)
(d) Finance costs		
Finance charges on lease liabilities	**(8.0)**	(8.7)
Discount unwinding on net present value of provision for restoration	**(2.1)**	(1.2)
Interest expense	**(0.4)**	(0.8)
Other finance costs	**(1.2)**	(0.3)
Total finance costs	**(11.7)**	(11.0)
(e) Other expenses		
Corporate	**(9.2)**	(7.8)
Realised losses on cash flow hedges	**(7.2)**	–
Share-based payments expense	**(2.1)**	(3.8)
Social investments/sponsorships	**(1.8)**	–
Depreciation and amortisation – non-oil and gas assets	**(0.4)**	(0.3)
Loss on disposal of non-current assets	**(0.1)**	–
Other expenses	**–**	(0.3)
Total other expenses	**(20.8)**	(12.2)

Note 5. Income Tax

(a) Income Tax (Expense)/Benefit Recognised in the Condensed Consolidated Statement of Profit or Loss and Other Comprehensive Income

	CONSOLIDATED HALF-YEAR ENDED 31 DEC 2022 US$M	CONSOLIDATED HALF-YEAR ENDED 31 DEC 2021 US$M
Income tax (expense)/benefit comprises		
Current income tax	**(52.8)**	(21.1)
Deferred income tax	**14.0**	47.4
Total income tax (expense)/benefit	**(38.8)**	26.3
The prima facie tax on profit/(loss) before income tax is reconciled to tax (expense)/benefit as follows:		
Prima facie tax (expense)/benefit on profit/(loss) before income tax, calculated at the Australian tax rate of 30%	**(34.9)**	37.2
(Add)/subtract the tax effect of:		
Share-based payments expense (non-cash)	**(0.4)**	(0.7)
Other non-deductible items	**(0.9)**	(1.4)
Social investments/sponsorships[a]	**1.1**	–
Tax losses and temporary tax differences not recognised	**–**	(0.1)
Difference in overseas tax rates	**(5.0)**	4.6
Foreign exchange differences	**1.3**	(13.3)
Total income tax (expense)/benefit	**(38.8)**	26.3

(a) This is a scheme which under Brazilian tax law permits a company when paying tax to direct a portion of this payment to specific government approved projects. There is no net cost to the Company as this amount replaces tax payable. It is classified as an expense in the financial statements rather than within income tax.

(b) Deferred Tax Balances

	BALANCE AS AT 1 JULY 2022 US$M	CHARGED (CREDITED) TO PROFIT OR LOSS US$M	CHARGED (CREDITED) DIRECTLY TO EQUITY US$M	BALANCE AS AT 31 DECEMBER 2022 US$M
Temporary differences				
Provisions and accruals	19.6	7.2	–	**26.8**
Equity raising transaction costs	0.2	(0.1)	–	**0.1**
Unrealised foreign currency losses/(gains)/translation adjustment	1.5	0.9	–	**2.4**
Fair value movement of financial liabilities	79.6	0.1	–	**79.7**
Farm-out expenditures	0.1	–	–	**0.1**
Right-of-use assets	(95.4)	12.5	–	**(82.9)**
Lease liabilities	98.2	(6.2)	–	**92.0**
Hedge premium	(4.5)	(0.3)	–	**(4.8)**
Net changes of cash flow hedges	21.2	–	(12.8)	**8.4**
Other	0.3	(0.1)	–	**0.2**
Total temporary differences	120.8	14.0	(12.8)	**122.0**
Unused tax losses				
Tax losses	2.2	1.1	–	**3.3**
Total unused tax losses	2.2	1.1	–	**3.3**
Net deferred tax assets/(liabilities)	123.0	15.1	(12.8)	**125.3**
Presented in the condensed consolidated statement of financial position as follows:				
Deferred tax assets	123.0			**125.3**

Note 6. Segment Information

(a) Description of Segments

The Group has identified its operating segments based on the internal reports that are reviewed and used by the Group's Executive Management Team (identified as the 'chief operating decision maker') in assessing performance and in determining the allocation of resources.

The operating segments are based on the Group's geographical location of its operations.

The Group has identified operating segments based on the following two geographic locations:

- Australia – in which the Group was involved in the exploration and evaluation of hydrocarbons in an offshore exploration permit area: WA-482-P. This permit was surrendered in September 2022; and
- Brazil – in which the Group is currently involved in the exploration, development and production of hydrocarbons in four offshore blocks: Block BM-S-40, Block S-M-1037, Block S-M-1101, and Block S-M-1537.

'All other segments' include amounts of a corporate nature not specifically attributable to an operating segment. The comparative period included costs associated with closure of the Group's Peruvian Branches.

The accounting policies of the reportable operating segments are the same as the Group's accounting policies.

Segment revenues and results do not include transfers between segments as intercompany balances are eliminated on consolidation.

Employee benefits expense and other expenses, which are associated with exploration and evaluation activities and specifically relate to an area of interest, are allocated to the area of interest and are either expensed or capitalised using the successful efforts method of accounting.

The amounts provided to the chief operating decision maker with respect to total assets and total liabilities are measured in a manner consistent with that of the consolidated financial statements. Reportable segment assets and segment liabilities are equal to consolidated total assets and total liabilities respectively. These assets and liabilities are allocated in accordance with the operations of the segment.

Note 6. Segment Information continued

(a) Operating Segments

SEGMENT PERFORMANCE	AUSTRALIA US$M	BRAZIL US$M	ALL OTHER SEGMENTS US$M	CONSOLIDATED US$M
Result for half-year ended 31 December 2022				
Revenue	**–**	**299.4**	**–**	**299.4**
Other income	**0.1**	**1.0**	**–**	**1.1**
Total segment revenue and other income	**0.1**	**300.4**	**–**	**300.5**
Expenses				
Business development and other project costs	**(0.5)**	**(1.0)**	**–**	**(1.5)**
Cost of sales	**–**	**(148.3)**	**–**	**(148.3)**
Depreciation and amortisation expense – non-oil and gas assets	**(0.1)**	**(0.3)**	**–**	**(0.4)**
Exploration expenses	**–**	**(1.7)**	**–**	**(1.7)**
Finance costs	**–**	**(11.7)**	**–**	**(11.7)**
Realised losses on cash flow hedges	**–**	**(7.2)**	**–**	**(7.2)**
Corporate expenses	**(5.4)**	**(3.8)**	**–**	**(9.2)**
Social investments/sponsorships	**–**	**(1.8)**	**–**	**(1.8)**
Other	**–**	**(0.1)**	**–**	**(0.1)**
Net foreign currency gains/(losses)	**0.8**	**(0.5)**	**–**	**0.3**
Change in fair value of contingent consideration	**–**	**(0.4)**	**–**	**(0.4)**
Share-based payments expense	**(1.6)**	**(0.5)**	**–**	**(2.1)**
Profit/(loss) before income tax	**(6.7)**	**123.1**	**–**	**116.4**
Income tax (expense)/benefit	**1.5**	**(40.3)**	**–**	**(38.8)**
Profit/(loss) for the period	**(5.2)**	**82.8**	**–**	**77.6**
Result for half-year ended 31 December 2021				
Revenue	–	186.5	–	186.5
Other income	–	0.1	–	0.1
Total segment revenue and other income	–	186.6	–	186.6
Expenses				
Business development and other project costs	(0.2)	(0.7)	–	(0.9)
Cost of sales	–	(104.4)	–	(104.4)
Depreciation and amortisation expense – non-oil and gas assets	(0.2)	(0.1)	–	(0.3)
Exploration expenses	(0.2)	(1.4)	(0.1)	(1.7)
Finance costs	–	(11.0)	–	(11.0)
Corporate expenses	(5.8)	(1.6)	(0.5)	(7.9)
Other	–	(0.1)	(0.1)	(0.2)
Net foreign currency gains/(losses)	2.1	1.7	(0.4)	3.4
Change in fair value of contingent consideration	–	(183.8)	–	(183.8)
Share-based payments expense	(3.3)	(0.5)	–	(3.8)
Profit/(loss) before income tax	(7.6)	(115.3)	(1.1)	(124.0)
Income tax benefit	1.7	24.6	–	26.3
Profit/(loss) for the period	(5.9)	(90.7)	(1.1)	(97.7)
Total segment assets				
As at 31 December 2022	40.4	1,216.3	0.1	1,256.8
As at 30 June 2022	49.3	1,114.7	0.2	1,164.2
Total segment liabilities				
As at 31 December 2022	3.5	874.2	0.0	877.7
As at 30 June 2022	4.8	883.1	0.1	888.0

Note 7. Oil and Gas Assets

	PRODUCTION ASSET US$M	DEVELOPMENT ASSET US$M	RIGHT OF USE ASSETS – FPSO VESSEL US$M	CONSOLIDATED TOTAL US$M
At 30 June 2022				
At cost	496.2	46.5	354.7	897.4
Accumulated depreciation	(91.8)	–	(72.6)	(164.4)
Carrying amount at end of financial year	404.4	46.5	282.1	733.0
Half-year ended 31 December 2022				
Balance at beginning of financial period	404.4	46.5	282.1	733.0
Additions	53.4	85.2	–	138.6
Transfers from property, plant and equipment	12.1	–	–	12.1
Remeasurement of lease arrangements	–	–	(0.8)	(0.8)
Depreciation expense	(47.5)	–	(34.2)	(81.7)
Borrowing costs capitalised[i]	–	1.7	–	1.7
Increase in provision for restoration[ii]	10.3	–	–	10.3
Carrying amount at end of half-year	432.7	133.4	247.1	813.2
At 31 December 2022				
At cost	**572.0**	**133.4**	**353.9**	**1,059.3**
Accumulated depreciation	**(139.3)**	**–**	**(106.8)**	**(246.1)**
Carrying amount at end of half-year	**432.7**	**133.4**	**247.1**	**813.2**

(i) The capitalised borrowing costs relate to an apportionment of the interest and fees incurred in connection with the syndicated loan facility (refer to Note 9) relating to the Patola development, which meets the definition of a qualifying asset.

(ii) Includes the addition of restoration obligations relating to the Patola wells, offset by an increase in the discount rate on total restoration provisions.

Note 8. Property, Plant and Equipment

	PLANT & EQUIPMENT US$M	RIGHT OF USE ASSETS US$M	CONSOLIDATED TOTAL US$M
At 30 June 2022			
At cost	13.7	2.4	16.1
Accumulated depreciation	(1.8)	(1.0)	(2.8)
Carrying amount at end of financial year	11.9	1.4	13.3
Half-year ended 31 December 2022			
Balance at beginning of financial period	**11.9**	**1.4**	**13.3**
Additions	**2.4**	**–**	**2.4**
Disposals	**(0.3)**	**–**	**(0.3)**
Transfers to oil and gas assets	**(12.1)**	**–**	**(12.1)**
Depreciation expense	**(0.1)**	**(0.3)**	**(0.4)**
Carrying amount at end of half-year	**1.8**	**1.1**	**2.9**
At 31 December 2022			
At cost	**3.7**	**2.4**	**6.1**
Accumulated depreciation	**(1.9)**	**(1.3)**	**(3.2)**
Carrying amount at end of half-year	**1.8**	**1.1**	**2.9**

Note 9. Borrowings

	CONSOLIDATED	
	31 DEC 2022 US$M	30 JUNE 2022 US$M
Non-Current		
Syndicated loan facility – secured	**30.0**	30.0
Less transaction costs(i)	**(2.4)**	(2.9)
Total non-current borrowings	**27.6**	27.1

(i) Includes remaining unamortised transaction costs associated with the syndicated loan facility and excludes costs that have been capitalised as part of Oil and Gas Assets in relation to qualifying assets.

During November 2021, Karoon Energy Ltd's wholly owned subsidiary, Karoon Petróleo & Gás Ltda, reached financial close on a reserve-based, non-recourse, syndicated loan facility with Deutsche Bank AG, ING Belgium SA/NV, Macquarie Bank Limited and Shell Western Supply and Trading Limited. In April 2022, an additional accordion facility, contemplated by the syndicated loan facility, was established.

The facility is secured over the shares in and assets of Karoon Petróleo & Gás Ltda, including its interest in the Baúna BM-S-40 concession.

The total available amount under the facility, including the accordion, is $210 million. At 31 December 2022, $30 million has been drawn down, with $180m remaining undrawn.

Interest on drawn amounts is charged at SOFR, including a credit adjustment spread of 0.26%, plus a margin of 4.25% p.a. A commitment fee is charged on undrawn available amounts at 1.7% p.a. The facility has a final maturity date of the earlier of 31 March 2025 or the quarter where the remaining reserves are forecast to be ≤ 25% of the initial approved reserves. The availability period is anticipated to continue into the September quarter, but not longer than 30 September 2023, after which the unutilised commitments shall be cancelled. Repayments will be based on the total outstanding reduction schedule with the facility amortising semi-annually on a straight-line basis from 30 September 2023 to maturity.

Karoon is also required to enter into oil hedging to ensure forecasted oil production is within a minimum and maximum hedge ratio.

The Group has complied with all loan covenants throughout the reporting period.

Note 10. Other Financial Assets and Liabilities

	CONSOLIDATED	
	31 DEC 2022 US$M	30 JUNE 2022 US$M
Assets		
Non-Current		
Derivative financial instruments – cash flow hedges(i)	**1.4**	–
Total assets	**1.4**	–
Liabilities		
Current		
Derivative financial instruments – cash flow hedges(i)	**11.5**	40.8
Embedded derivative – contingent consideration payable(ii)	**84.6**	84.6
Non-Current		
Derivative financial instruments – cash flow hedges(i)	**–**	8.3
Embedded derivative – contingent consideration payable(ii)	**214.1**	213.7
Total liabilities	**310.2**	347.4

(i) During the prior period, the Group entered into Brent oil price derivative hedges, via a collar structure consisting of bought put and sold call options covering the period from December 2021 to March 2024. The purpose of the hedges is to protect operating cash flows from a portion of crude oil sales against the risk of lower oil prices while retaining significant exposure to oil price upside. The hedges are also a requirement of the syndicated loan facility (refer to Note 9).

The bought put and sold call options have been designated as cash flow hedges, and in the current period, changes in the fair value of the options of $37.3m pre-tax ($24.5 net of tax) have been recognised in the cost of hedging reserve within equity, of which $1.3m pre-tax ($0.8m net of tax) has been reclassified to profit or loss. As at 31 December 2022, no losses were recognised in profit or loss for hedge ineffectiveness. The fair value of derivative financial assets and liabilities was determined based on valuation techniques which employ the use of market observable inputs representing a Level 2: fair value measurement.

At 31 December 2022, the Group had the following outstanding hedges:

FINANCIAL YEAR	BOUGHT PUT STRIKE (US$/BBL)	PUT VOLUME ('000 BBL)	SOLD CALL AVERAGE STRIKE (US$/BBL)	CALL VOLUME ('000 BBL)
2023	65	1,470	84.1	1,401
2024	65	2,040	91.8	1,578
		3,510		2,979

	CONSOLIDATED	
	31 DEC 2022 US$M	30 JUNE 2022 US$M
(ii) Reconciliation of contingent consideration payable		
Balance at the beginning of the financial period	**298.3**	71.2
Unrealised fair value changes recognised in profit or loss during the period	**0.4**	227.1
Total contingent consideration payable at fair value	**298.7**	298.3

(a) The contingent consideration arrangement for the acquisition of Baúna requires Karoon's wholly owned subsidiary, Karoon Petróleo & Gás Ltda., to pay Petrobras contingent consideration of up to US$285 million.

The contingent consideration accrues interest at 2% per annum from 1 January 2019 with any amounts payable by 31 January after the completion of the relevant testing period. The relevant testing periods are each calendar year from 2022 to 2026 inclusive and are based on the achievement of annual average Platts Dated Brent oil prices thresholds commencing at ≥US$50 and ending at ≥US$70 a barrel.

Note 10. Other Financial Assets and Liabilities continued

After the testing of each year, any amount deemed not payable is cancelled and not carried forward. The amount payable each calendar year excluding interest depending on achievement of certain oil prices is disclosed below:

AVERAGE BRENT PRICE (IN US$ UNITS)	CY2022	CY2023	CY2024	CY2025	CY2026	TOTAL
B < 50	–	–	–	–	–	–
50 <= B < 55	3	3	3	2	2	13
55 <= B < 60	17	17	17	8	4	63
60 <= B < 65	34	34	34	15	6	123
65 <= B < 70	53	53	53	24	10	193
B >= 70	78	78	78	36	15	285

As at 30 June 2022, based on the Group's internal assessment of future oil prices and industry consensus, the Brent oil forecast was revised and it was assessed that the amount payable under the contingent consideration arrangement would be the maximum amount payable of $285m plus interest.

At 31 December 2022, based on the Group's internal assessment of future oil prices and industry consensus, the amount payable continues to accrue at the maximum amount of $285m plus interest. $84.6m, the amount payable in respect of the 2022 calendar year, has been recognised a current liability, and has subsequently been paid in January 2023. The fair value of the total amount payable has been revised upwards by $0.4m due to a revision in the discount rate. A discount rate of 3.49% and 2% interest per annum has been applied in the calculation of the present value at 31 December 2022.

Note 11. Contributed Equity

(a) Contributed Equity

	CONSOLIDATED	
	31 DEC 2022 US$M	30 JUNE 2022 US$'M
Ordinary shares, fully paid	**907.5**	907.5
Total contributed equity	**907.5**	907.5

(b) Movement in Ordinary Shares

DATE	DETAILS	NUMBER OF ORDINARY SHARES	US$M
1 July 2021	Opening balance in previous financial year	553,770,529	905.1
	Exercise of options	2,383,899	2.4
	Performance rights conversion	1,930,924	–
30 June 2022	Balance at end of previous financial year	558,085,352	907.5
	Performance rights conversion	4,598,004	–
31 December 2022	Balance at end of half-year	562,683,356	907.5

Note 12. Dividends

There were no ordinary dividends declared or paid during the financial half-year by the Company (31 December 2021: $Nil).

Note 13. Commitments

	CONSOLIDATED	
	31 DEC 2022 US$M	30 JUNE 2022 US$M
(a) Capital and Service Expenditure Commitments		
Contracts for capital and service expenditure in relation to assets not provided for in the condensed consolidated financial statements and payable. Note, the service commitments as at 31 December 2022 include the provision of services related to the charter of the FPSO acquired as part of the Baúna acquisition.		
Capital commitments for Baúna workovers and Patola Development		
Not later than one year	**20.3**	75.9
Total capital commitments	**20.3**	75.9
Service commitments		
Not later than one year	**13.0**	11.5
Later than one year but not later than five years	**26.5**	31.9
Total service commitments	**39.5**	43.4
Total capital and service expenditure commitments	**59.8**	119.3
(b) Exploration Expenditure Commitments		
The Group has guaranteed commitments for exploration expenditure arising from obligations to governments to perform minimum exploration and evaluation work and expend minimum amounts of money pursuant to the award of exploration tenement Block S-M-1537 (30 June 2022: Block S-M-1537) not provided for in the consolidated financial statements and payable.		
Later than one year but not later than five years	**3.5**	3.5
Total guaranteed exploration expenditure commitments	**3.5**	3.5

Note, the figures above do not include any commitments in relation to S-M-1037 and S-M-1101 relating to the Neon and Goiá light oil discoveries. In accordance with Brazilian regulatory requirements, during January 2019 Karoon submitted both a Final Discovery Evaluation Report and Declaration of Commerciality for the discoveries. This transitioned the Blocks for Brazilian regulatory requirements, from the exploration phase to the development phase. However, it does not mean that Karoon has reached, nor is compelled to reach, a final investment decision ('FID') to proceed into a Development of the discoveries. Prior to a FID being reached, Karoon anticipates drilling 'control wells' to assist with delineating the Neon discovery, confirming reservoir quality and assisting with the planning and design of development wells and infrastructure. Drilling of the first control well was completed on 23 January 2023 and wireline logs were acquired. The current expectation is that the second control well will spud by end-February 2023.

Estimates for future exploration expenditure commitments to government are based on estimated well and seismic costs, which will change as actual drilling locations and seismic surveys are completed and are calculated in current dollars on an undiscounted basis. The exploration and evaluation obligations may vary significantly as a result of renegotiations with relevant parties. The commitments may also be reduced by the Group entering into farm-out agreements, which are typical of the normal operating activities of the Group and by relinquishing exploration tenements.

Note 14. Contingent Liabilities

There has been no material change to the contingent liabilities since 30 June 2022.

Note 15. Subsequent Events

The Half-Year Financial Report was authorised for issue by the Board of Directors on 22 February 2023. The Board of Directors has the power to amend and reissue the condensed consolidated financial statements and notes.

Since 31 December 2022, there have been no material events that have occurred.

DIRECTORS' DECLARATION

The Directors declare that:

(a) in the Directors' opinion, the condensed consolidated financial statements and notes, set out on pages 18 to 32, are in accordance with the *Corporations Act 2001*, including:

   (i) complying with Australian Accounting Standard AASB 134 '*Interim Financial Reporting*' and the *Corporations Regulations 2001*; and

   (ii) giving a true and fair view of the Group's financial position as at 31 December 2022 and of its performance for the financial half-year ended on that date; and

(b) in the Directors' opinion, there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

This Directors' Declaration is made in accordance with a resolution of the Directors.

On behalf of the Directors:

Mr Bruce Phillips
Independent Non-Executive Chairman

Dr Julian Fowles
Chief Executive Officer and Managing Director

22 February 2023
Melbourne

Independent auditor's review report to the members of Karoon Energy Ltd

Report on the half-year financial report

Conclusion

We have reviewed the half-year financial report of Karoon Energy Ltd (the Company) and the entities it controlled during the half-year (together the Group), which comprises the condensed consolidated statement of financial position as at 31 December 2022, the condensed consolidated statement of profit or loss and other comprehensive income, condensed consolidated statement of changes in equity and condensed consolidated statement of cash flows for the half-year ended on that date, significant accounting policies and explanatory notes and the directors' declaration.

Based on our review, which is not an audit, we have not become aware of any matter that makes us believe that the accompanying half-year financial report of Karoon Energy Ltd does not comply with the *Corporations Act 2001* including:

1. giving a true and fair view of the Group's financial position as at 31 December 2022 and of its performance for the half-year ended on that date
2. complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

Basis for conclusion

We conducted our review in accordance with ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity* (ASRE 2410). Our responsibilities are further described in the *Auditor's responsibilities for the review of the half-year financial report* section of our report.

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional & Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to the audit of the annual financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

Responsibilities of the directors for the half-year financial report

The directors of the Company are responsible for the preparation of the half-year financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the half-year financial report that gives a true and fair view and is free from material misstatement whether due to fraud or error.

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2 Riverside Quay, SOUTHBANK VIC 3006, GPO Box 1331, MELBOURNE VIC 3001
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pwc

Auditor's responsibilities for the review of the half-year financial report

Our responsibility is to express a conclusion on the half-year financial report based on our review. ASRE 2410 requires us to conclude whether we have become aware of any matter that makes us believe that the half-year financial report is not in accordance with the *Corporations Act 2001* including giving a true and fair view of the Group's financial position as at 31 December 2022 and of its performance for the half-year ended on that date, and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

A review of a half-year financial report consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

PricewaterhouseCoopers

PricewaterhouseCoopers

Graeme McKenna

Graeme McKenna
Partner

Melbourne
22 February 2023

Remuneration Report (Audited)

Dear Shareholders,

On behalf of the Board of Directors I am pleased to present to you the Karoon Energy Ltd Remuneration Report for the financial year ended 30 June 2022.

Overview

The 2021/2022 year has again been characterised by risks and uncertainties on many fronts globally. Notwithstanding global economic turbulence caused by the war in Ukraine, rising interest rates, inflation, recessionary fears and currently strong crude oil prices, it has been a year in which Karoon has continued to build its reputation as a safe and reliable operator.

Over the 2022 financial year, the following significant strategic and operational milestones have been achieved:

- Achieved production uptime of 99% (excluding scheduled outages) with no material safety or environmental incidents;
- Produced 4.64 million barrels of crude oil during the period for total revenue of $385 million;

COVID-19 was effectively managed across our facilities with no COVID-19 related production outages;

- Financial close was reached on a $160 million reserve based, non-recourse, syndicated debt facility, later expanded by over 30% through a $50 million accordion facility;
- The restructure of our senior management team was completed with the appointment of Antonio Guimarães (as EVP and President of Karoon Brazil) and Ray Church (as EVP and Chief Financial Officer);
- Completed a "strategic refresh" covering (among other things):
  - » Brazil strategy;
  - » operating and delivery excellence;
  - » growth, including organic (e.g. Neon project) and inorganic (e.g. Brazil & Australian M&A);
  - » sustainability; and
  - » funding and capital priorities;
- Developed a "five pillar" sustainability strategy and commenced implementing it by:
  - » becoming carbon neutral on Baúna-Patola emissions for FY2021;
  - » entering into an agreement with Shell Western Supply and Trading Limited to purchase sufficient verified emissions reductions, between 2022 and 2030, to offset an estimated 60% of Baúna-Patola scope 1 and scope 2 greenhouse gas emissions;
- Committed to drilling a control well and, subject to the results of that well, a second control well in the Neon oil discovery offshore Brazil to further advance the understanding of the discovery;
- Executed contracts for the Baúna intervention campaign and the operations commenced within the announced window; and
- Whilst seeking to advance Karoon's merger and acquisition strategy, a disciplined approach was adopted to end further consideration of a potential transaction with Enauta in respect of the Atlanta oil field in the Santos Basin, offshore Brazil. Karoon will continue to identify and evaluate appropriate merger and acquisition targets.

2022 Financial Year Remuneration Outcomes

In respect of FY2022, Karoon's remuneration settings worked as they should to reward high performance outcomes in a responsible manner. In this regard, it is noted that:

- Short Term Incentive ("STI") – based on the significant progress detailed above and achieving Karoon's strategic targets set at the beginning of the 2022 financial year (associated with production, opex, capex, Neon strategy, the Baúna intervention campaign, the Patola development and ESG), 67.5% of the possible STI outcome was achieved. This STI is to be paid 50% in cash and 50% in performance rights with such performance rights to be issued after the release of the Company's FY2022 full year financial results and subject to the satisfaction of a 12-month employment retention period. For KMP other than the CEO and Managing Director, a component of their STI was granted based on the satisfaction of role-specific objectives.

- Long Term Incentive ("LTI") – a 100% LTI outcome was earned due to an absolute total shareholder return ('TSR') of 32.1% per annum (in excess of the required threshold of 14% per annum), and the Company's relative shareholder return positioning Karoon at the 100% percentile (as compared to a group of peer companies), over the prior 3-year period.

- Base Board and committee fees remained unchanged for FY2022.

Remuneration Strategy and Guiding Principles

Karoon's guiding principles for its remuneration framework are as follows:

- **Safety, culture and ethics:** ensuring that clear vesting gateways exist based on appropriate safety and ethical outcomes. If outcomes do not meet the relevant standards, these gateways will block "at-risk" remuneration payments.

- **Shareholder value is paramount:**

  » remuneration outcomes (particularly incentive-based outcomes) are designed to take account of share price movements across the reporting period and therefore, the value delivered to shareholders;

  » a close alignment is created between operational performance, reward and sustained growth in shareholder value; and

  » as Karoon has now transitioned from explorer to producer, it is recognised that shorter term shareholder returns, such as dividend payments, will also now be considered.

- **People:**

  » remuneration and people issues are considered by the People, Culture and Governance Committee of the Board and environmental and social issues by the Sustainability and Operational Risk Committee of the Board. Nonetheless, all relevant decision making and associated discussion remains the responsibility of the Board;

  » our remuneration structures are designed to attract, motivate and retain the best people whilst remunerating them reasonably and competitively; and

  » we encourage our people to hold equity in Karoon which builds a culture of viewing management decisions as an owner, thereby helping to further align executives' and shareholders' interests. In relation to this, during 2022, a new management shareholding policy has been introduced under which KMP are now required to maintain a shareholding in the Company equal to 50% of their first year, base salary (after-tax) within the later of three years after their initial appointment as an executive and 30 June 2024.

- **Environment, Social and Governance (ESG):** ESG considerations are integrated into our remuneration structures. In FY2022, this involved, as an STI hurdle, management developing and commencing the implementation of a Board endorsed sustainability strategy which covers HSE, climate (including carbon management), people and human rights, community (including social programs) and environment.

- **Transparency:** remuneration measures, outcomes and reporting are as simple and transparent as possible for shareholders and other stakeholders.

Remuneration Report (Audited) continued

2023 Financial Year Remuneration Settings

Looking to the 2023 financial year, the remuneration structure for Australian and Brazilian staff members will be reviewed for reasonableness and competitiveness.

The base Board and Committee fees paid to the Non-Executive Chairman and Non-Executive Directors will be increased by 5%, while the fees paid to the Chairs of Board committees will be increased by A$5,000 per annum. The increase in respect of Non-Executive Directors base Board fees is the first increase in over 10 years and, in respect of the Non-Executive Chairman's base fee, is the first increase in 7 years.

Summary

Karoon's strategy and remuneration structure is designed to link remuneration outcomes to shareholder value which we believe it has done for FY2022 by rewarding the achievement of significant operational and strategic goals and through achieving relative share price out-performance compared to Karoon's peer group.

As always, we will continue to engage with our shareholders, proxy advisors and our wider group of stakeholders to seek feedback so we can continue to refine and improve our remuneration framework and the associated disclosures.

Yours sincerely

Mr Peter Turnbull AM
Chair, People, Culture and Governance Committee

25 August 2022

Section 1. Introduction

The Board of Directors is pleased to provide Karoon's Remuneration Report, which details the remuneration for its KMP, defined as those persons having the authority and responsibility for planning, directing and controlling, directly or indirectly, the activities of the Group.

For the financial year ended 30 June 2022, KMP disclosed in the Remuneration Report are as follows:

NAME	POSITION	TERM AS KMP
Executive Directors		
Dr Julian Fowles	Chief Executive Officer and Managing Director	Full financial year
Non-Executive Chairman		
Mr Bruce Phillips	Independent Non-Executive Chairman	Full financial year
Non-Executive Directors		
Ms Luciana Rachid	Independent Non-Executive Director	Full financial year
Mr Clark Davey	Independent Non-Executive Director	Full financial year
Mr Peter Turnbull	Independent Non-Executive Director	Full financial year
Mr Peter Botten	Independent Non-Executive Director	Full financial year
Other KMP		
Mr Ray Church	Executive Vice President and Chief Financial Officer	Commenced as Executive Vice President (EVP) and Chief Financial Officer on 27 September 2021
Mr Antonio Guimarães	Executive Vice President and President Karoon Brazil	Commenced as EVP and President Karoon Brazil on 1 October 2021
Mr Edward Munks	Chief Operating Officer	Ceased as Chief Operating Officer on 30 September 2021
Mr Scott Hosking	Chief Financial Officer (Group)	Ceased as Chief Financial Officer on 30 September 2021
Mr Ricardo Abi Ramia	Senior VP Operations	Ceased as KMP on 1 October 2021

For the purposes of the Remuneration Report:

(i) 'base salary' means cash salary (exclusive of superannuation and before subtracting any salary sacrifice items);

(ii) 'executive' means the Chief Executive Officer and Managing Director and other KMP of the Group;

(iii) 'fixed remuneration' has the meaning given on page 53;

(iv) 'other KMP' means those KMP referred to above under the heading 'Other KMP';

(v) 'total remuneration' means fixed remuneration plus variable remuneration; and

(vi) 'variable remuneration' means STI and LTI.

The Remuneration Report for the financial year ended 30 June 2022 outlines the remuneration arrangements of KMP of the Group in accordance with the requirements of the *Corporations Act 2001* and its regulations. The information provided in this Remuneration Report has been audited by Karoon's external auditor, as required by Section 308(3C) of the *Corporations Act 2001*. The Remuneration Report forms part of this Directors' Report.

Remuneration Report (Audited) Continued

Section 2. Board and People, Culture and Governance Committee Oversight

To assist in ensuring good remuneration governance at Karoon, the Board of Directors established a People, Culture and Governance Committee that provides oversight and recommendations to the Board on all aspects of the remuneration arrangements for sub-CEO executives.

The People, Culture and Governance Committee currently consists of a majority of independent Non-Executive Directors and is responsible for reviewing and making recommendations to the Board of Directors regarding (among other things):

- the quantum of sub-CEO executive remuneration;
- the sub-CEO executive remuneration framework, including the operation of, and performance-based outcomes under, Karoon's share-based incentive schemes;
- the recruitment, retention and termination policies and procedures for sub-CEO executives; and
- related party remuneration.

The Board of Directors, assisted by the People, Culture and Governance Committee, conducts annual remuneration reviews for its Non-Executive Chairman, Non-Executive Directors, executives and all employees to ensure that remuneration remains market competitive, fair and aligned with both market practice and the best interests of shareholders.

The Board is responsible for all aspects of the remuneration of the CEO and Managing Director.

Further information on the role and responsibilities of the People, Culture and Governance Committee is contained in the People, Culture and Governance Committee Charter, which can be found under the Governance tab on Karoon's website at **www.karoonenergy.com.au**.

2021 Remuneration Report Vote

At the Company's 2021 Annual General Meeting, Karoon's 2021 Remuneration Report received a 99.48% vote FOR on a poll.

At the Annual General Meeting, no questions were asked in relation to the remuneration report.

Share Trading Policy

The trading of ordinary shares by Non-Executive Directors and executives is subject to, and conditional upon, compliance with Karoon's Share Trading Policy.

Under Karoon's Share Trading Policy, an individual may not limit his or her exposure to risk in relation to securities (including unlisted share options and performance rights). Directors and executives are prohibited from entering into any hedging arrangements over unvested share options or performance rights under Karoon's share-based remuneration schemes. To gain approval to trade and ensure that trading restrictions are not in force any employee wishing to trade in Karoon securities must consult the Company Secretary, whilst the Executive Vice President and President Karoon Brazil, the Company Secretary or any Director wishing to trade in Karoon securities must consult the Chairman, whilst the Chairman must consult and seek approval of the Audit and Risk Committee Chair. All trades by Directors and executives during the financial year ended 30 June 2022 were conducted in compliance with Karoon's Share Trading Policy.

Karoon's Share Trading Policy can be found under the Governance tab on Karoon's website at **www.karoonenergy.com.au**.

Section 3. Executive Remuneration

The Board of Directors has developed a remuneration policy that ensures executive remuneration supports the current business strategy and needs of the business. In particular, the decision to use performance tested share-based remuneration (in addition to cash based incentive payments) for its incentive plans reflects the Board of Directors' belief that this best aligns executive and shareholder interests in the short and long-term. Karoon's success is measured by the delivery of its strategic objectives in the short-term and a clear demonstration of shareholder value creation in the long-term.

Broadly, the objectives of Karoon's executive remuneration framework are to ensure:

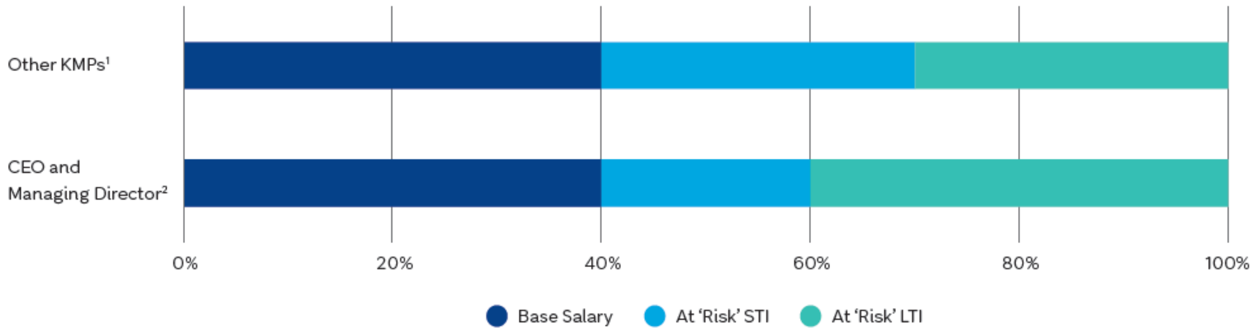
- remuneration is reasonable and competitive in order to attract, retain and motivate talented and high calibre executives capable of managing Karoon's diverse international operations;
- remuneration is set at a level acceptable to shareholders, having regard to Karoon's performance, and rewards individual achievements;
- remuneration structures create alignment between performance, reward and sustained growth in shareholder value;

- remuneration outcomes provide recognition of contribution to overall long-term growth in the value of Karoon's asset portfolio and are transparent to both participants and shareholders; and
- remuneration incentivises the best possible outcomes for the broader stakeholder community, including sustainability and safety, along with best practice in preventing bribery and/or corruption.

A. Executive Remuneration Framework for the Financial Year Ended 30 June 2022

The following table summarises the target remuneration mix for executives for the financial year ended 30 June 2022, based on maximum achievement of incentive plan outcomes:

Remuneration Mix – financial year ended 30 June 2022 (as a percentage of total remuneration)



1. "Other KMPs" excludes the remuneration mix of Mr Ricardo Abi-Ramia who ceased as a KMP on 1 October 2021. Mr Abi-Ramia's remuneration mix comprises 50% 'fixed', 25% at 'risk' STI and 25% at 'risk' LTI. "Other KMPs" also excludes the remuneration mix of Mr Scott Hosking and Mr Edward Munks who were not entitled to an 'at risk' STI or 'at risk' LTI but were paid a cash bonus for the period from 1 July 2021 to 30 September 2021 (being the date of the cessation of their employment). The percentage of the other KMPs' at 'risk' STI is based on fixed remuneration and at 'risk' LTI is based on base salary.
2. The percentage of the CEO and Managing Director's at 'risk' STI and at 'risk' LTI is based on base salary.

Set out below is a summary of the STI and LTI opportunity available to the CEO and Managing Director, EVP and Chief Financial Officer and EVP and President Karoon Brazil.

	CEO and Managing Director	EVP and Chief Financial Officer	EVP and President Karoon Brazil
STI opportunity	50% of Base Salary	75% of Fixed Remuneration	75% of Fixed Remuneration
LTI opportunity	100% of Base Salary	75% of Base Salary	75% of Base Salary

See pages 54-57 for additional information on the STI and LTI plans.

Fixed Remuneration

Fixed remuneration consists of base salary and superannuation contributions. It can also include any salary sacrifice items or non-monetary benefits including health insurance, motor vehicles, expatriate travel, certain membership and associated fringe benefits tax, depending on each individual's respective employment arrangements.

Fixed remuneration is reviewed annually by the Board. Broadly, fixed remuneration is positioned within a range that references the median of the relevant market for each role. Base salary of the former Chief Financial Officer, former Chief Operating Officer, the EVP and Chief Financial Officer and EVP and President Karoon Brazil did not increase during the financial year ended 30 June 2022. The Chief Executive Officer and Managing Director's base salary increased by 3.1% for the financial year ended 30 June 2022.

Superannuation

Other than the Chief Executive Officer and Managing Director who receives superannuation contributions equal to 9.5% of his base salary, the Australian executives of the Company received statutory superannuation contributions of 10% of base salary up to the maximum statutory contribution. Individuals may choose to sacrifice part of their salary to increase payments towards superannuation.

Social Security and Indemnity Fund Contributions

Karoon's Brazilian based executives are subject to specific Brazilian employment regulations, whereby the Group is required to contribute 27.3% of Brazilian cash compensation as social security to fund Government pensions paid in retirement. However, the executives upon retirement will only be entitled to a portion of this contribution. A further 8% of their base salary is required to be contributed to a Federal Severance Indemnity Fund ('FGTS'). In the situation of unfair dismissal without just cause, the Group would have to pay a fine equivalent to 50% of the accumulated balance of the individual's FGTS account.

In addition to the above, the Group pays an amount equal to 10% of the monthly salary paid to the EVP and President Karoon Brazil into a private pension fund for the benefit of the EVP and President Karoon Brazil.

Remuneration Report (Audited) Continued

Section 3. Executive Remuneration Continued

'At Risk' Remuneration

Karoon aims to align the interests of executives with those of shareholders by having a significant proportion of executive remuneration 'At Risk'. 'At Risk' remuneration represents the proportion of remuneration that requires pre-determined performance conditions to be met before the remuneration is vested to the executive. Annually, the Board reviews the financial and operational goals and targets, looking broadly at where the building blocks for long-term value exist, then sets performance conditions that generate a link between operating performance, remuneration received and value created for shareholders.

All executives that received grants of performance rights during the financial year ended 30 June 2022 received performance rights that were issued under the 2019 Performance Rights Plan ('2019 PRP').

STI Plan

The key features of the STI plan for the financial year ended 30 June 2022 ('FY2022 award') are outlined in the table below:

Participation	All executives. Participation in the STI Plan is at the discretion of the Board of Directors on the recommendation of the People, Culture and Governance Committee.
STI Opportunity	The STI opportunity level of each executive is a pre-determined proportion of an executives' total remuneration payable 50% in cash and 50% via a grant of performance rights. The quantum of performance rights received is to be determined by dividing 50% of the STI opportunity (determined to be available based on the satisfaction of applicable performance conditions) for each employee by Karoon's weighted average share price in the 20-trading day period after the date of the release of the Company's 2022 full year financial results. The STI opportunity available to an executive is determined as a percentage of fixed remuneration or base salary. The Board calculates the incentive value and establishes a maximum number of performance rights 'At Risk'. In respect of the former Chief Financial Officer and Chief Operating Officer, it was decided, given their cessation occurred part way through the 2022 financial year, that an at risk cash bonus (as opposed to an STI payable 50% in cash and 50% via a grant of performance rights) would be available with no deferral period.
Form of Incentive	Executives receive cash (50%) and performance rights (50%). The cash component of the FY2022 STI opportunity is paid following the achievement of applicable performance conditions. The quantum of performance rights to be received is to be determined by dividing 50% of the STI opportunity (determined to be available based on the satisfaction of applicable performance conditions) for each executive by Karoon's weighted average share price in the 20-trading day period after the date of the release of the Company's 2022 full year financial results. Any performance rights issued will remain 'At Risk' until the satisfaction of retention conditions to be met on 1 July 2023. Performance rights do not have a strike price. Each performance right provides the participant with the right to receive one fully paid ordinary share in Karoon, or its equivalent value, for no consideration. Under the rules of the PRP, ordinary shares issued or provided as a result of the exercise of vested and converted performance rights may be issued as new ordinary shares or ordinary shares acquired on market.
Performance Period	1 year.

Deferral Period	Performance rights which satisfy performance conditions are subject to a retention period of 12 months, being the continuation of employment, immediately following the satisfaction of performance conditions.
Performance Conditions	As part of the 2022 remuneration review, for the financial year ended 30 June 2022 the Board set out the FY2022 award for short-term incentives based on a mix of the following performance hurdles

	COMPANY-WIDE OBJECTIVES	ROLE-SPECIFIC OBJECTIVES
CEO and Managing Director	100%	Nil%
Other KMP	80%	20%

Company-wide Objectives

Company-wide Objectives were set by the Board at the beginning of the performance period.

The Company-wide Objectives included financial and operational objectives, project objectives and strategic targets.

Role-specific Objectives

Role-specific Objectives were set at the beginning of the performance period and related directly to individual/team specific responsibilities.

All short-term performance outcomes are tempered by both a gateway for safety outcomes and a clawback (negative discretion) provision in relation to any fatality and bribery and/or corruption issues.

Further details on the performance conditions, targets and outcomes for the FY2022 award are outlined below in the STI outcomes within Section 3B on page 57.

Grant Date	In respect of performance rights, the grant date occurs following the offer and acceptance of performance rights. However, any performance rights offered and accepted by the Chief Executive Officer and Managing Director are subject to shareholder approval at the next Annual General Meeting prior to issuance.
Termination of Employment	Unvested performance rights will lapse upon cessation of employment with Karoon, subject to the nature and circumstances of the termination and the discretion of the Board of Directors.
Change of Control	Upon a change of control, the Board of Directors may determine that a portion of the individual's unvested performance rights will vest based on pro-rata achievement of the performance conditions.
Link Between Performance and Reward	The STI framework is based on a set of challenging Company building goals, granted on a rolling short-term basis. Linking outcomes to operational performance develops an essential alignment between Karoon's year-to-year inherent value growth and rewards those who establish that value only when the goals are met. The Board assess the goals for the performance period annually in light of the long-term strategic building blocks and upcoming key value drivers within Karoon's operations, allowing for transparent measurement of performance against these objectives. The Board recognises the risks associated with offshore production and drilling and considers safety, anti-bribery and zero corruption paramount to its operations. Safety is used as a gateway for vesting conditions, while any fatality and bribery and corruption can be utilised to clawback incentives.

Remuneration Report (Audited) Continued

Section 3. Executive Remuneration Continued

LTI Plan

The key features of the LTI grant for the financial year ended 30 June 2022 are outlined in the table below:

Participation

All executives.

Participation in the LTI plan is at the discretion of the Board of Directors on the recommendation of the People, Culture and Governance Committee.

LTI Opportunity

The LTI opportunity available to an executive is determined as a percentage of base salary.

Form of Incentive

The quantum of performance rights received was determined by dividing the LTI opportunity for each executive by the value weighted average price of Karoon Energy ordinary shares for the 20 trading days post 20 September 2021 (being the date on which Karoon's 2021 full year financial results were released to the market).

Performance rights do not have a strike price. Each performance right provides the participant with the right to receive one fully paid ordinary share in Karoon, or its equivalent value, for no consideration. Under the rules of the PRP, ordinary shares issued or provided as a result of the exercise of vested and converted performance rights may be issued as new ordinary shares or ordinary shares acquired on-market.

Performance Period

3 years.

Performance Conditions

The LTI performance hurdles for the period commencing 1 July 2021 and ending 30 June 2024 are split 50% relative to TSR performance as assessed against a list of closely comparable and representative industry peer group companies, whose business models and/or regions of operations are similar to those of Karoon; and 50% Absolute TSR (based on compound annual growth rate (CAGR)), which is set at a range of 10% to 18%.

Vesting consideration details for the industry peer group companies is outlined below:

Performance Against Industry Peer Group	Proportion of Performance Rights Vesting
Less than 50th percentile	Nil%
At 50th percentile	50%
Between 50th and 75th percentile	50% plus 2% for each additional percentile ranking above the 50th percentile
At or above 75th percentile	100%
At 100% percentile	100%

Vesting consideration details for the Absolute TSR measure are set out below:

Absolute TSR (CAGR)	Proportion of Performance Rights Vesting
Less than 10%	Nil%
At 10%	50%
Between 10.01% and 17.99%	50% plus 6.25% for each additional percentage point above the 10% threshold
At or above 18.00%	100%

Grant Date

Grant date occurs following the offer and acceptance of performance rights. However, any performance rights offered and accepted by the Chief Executive Officer and Managing Director are subject to shareholder approval at the next Annual General Meeting prior to issue.

Exercise Period

Performance rights will remain exercisable for a period of 1 year following vesting.

Termination of Employment

Unvested (and unconverted) performance rights will lapse upon cessation of employment with Karoon, subject to the nature and circumstances of the termination and the discretion of the Board of Directors.

Change of Control

Upon a change of control, the Board of Directors may determine that a portion of the individual's unvested performance rights will vest, based on pro-rata achievement of the performance conditions.

Link Between Performance and Reward

The Board of Directors and People, Culture and Governance Committee consider it important to link remuneration to share price performance relative to Karoon's industry peer group companies and overall share price performance over the long-term. In the case where performance does not reach the 50th percentile, no incentive will be paid.

B. Executive Remuneration Outcomes

Relationship between the Executive Remuneration Framework and Company Performance

Karoon has a transparent performance-based remuneration structure in place that provides a direct link between Company performance and remuneration in the short and long-term. As part of this structure, executive rewards are directly linked to operational, safety and financial performance metrics along with relative market and absolute performance. 'At Risk' remuneration is only awarded if pre-determined Company building milestones are achieved or the Company outperforms an industry peer group of companies or achieves a minimum level of absolute return in the long term.

The tables below set out summary information about the Company's earnings, net assets and movements in shareholder wealth from 1 July 2017 to 30 June 2022.

FINANCIAL YEAR ENDED	30 JUNE 2022 US$'000	30 JUNE 2021 US$'000	30 JUNE 2020 US$'000	30 JUNE 2019[A] US$'000	30 JUNE 2018[A,B] US$'000
Revenue	**385,074**	170,809	–	–	–
Profit (loss) before income tax	**(89,838)**	(27,873)	(86,772)	(11,351)	(142,699)
Profit (loss) for financial year	**(64,451)**	4,384	(86,138)	(13,316)	(140,932)
Net assets at end of financial year	**276,201**	380,250	359,482	298,831	410,367

FINANCIAL YEAR ENDED	30 JUNE 2022	30 JUNE 2021	30 JUNE 2020	30 JUNE 2019[A]	30 JUNE 2018[A,B]
Share price at beginning of financial year	**A$1.33**	A$0.61	A$0.96	A$1.13	A$1.28
Share price at end of financial year	**A$1.74**	A$1.33	A$0.61	A$0.96	A$1.13
Basic profit (loss) per ordinary share (US$)	**(0.1159)**	0.0079	(0.1936)	(0.0550)	(0.5740)
Diluted profit (loss) per ordinary share (US$)	**(0.1159)**	0.0077	(0.1936)	(0.0550)	(0.5740)

A. The comparative financial information for the financial years ended 30 June 2019 and 30 June 2018 have been restated for the voluntary change in presentation currency from A$ to US$ at the prevailing average exchange rates for the profit and loss and year-end rate for the balance sheet for each respective year.

B. The comparative financial information for the financial year ended 30 June 2018 has not been restated for the impact of the voluntary change to successful efforts method of accounting for exploration and evaluation expenditure.

Performance Hurdles and STI Outcomes for the Financial Year Ended 30 June 2022

The table below outlines the Company-wide Objectives for the financial year ended 30 June 2022:

CRITERIA	SUMMARY OF HURDLE
Safety (0% – gateway)	TRIR of < 2 required for any award to proceed.
FINANCIAL AND OPERATIONAL OBJECTIVES (40%)	
Operational Performance and Budgeting	Achieve the challenging Baúna approved cost budget and operational targets.
PROJECT OBJECTIVES (30%)	
Neon Strategy	Progress the Company's strategy in respect of the development of the Neon/Goia project.
Baúna interventions	Commence and progress the Baúna intervention campaign within approved budget and programme window.
Patola development	Commence and progress the Patola development within approved budget and programme window.
	Reach financial close under the US$160M Syndicated Facility Agreement.
STRATEGIC (30%)	
M&A Strategy	Progress M&A strategy.
ESG	Develop and implement ESG strategy.
Anti-bribery and Corruption/ No Fatality (0% – clawback)	Negative discretion will be applied, if necessary, by the Board of Directors should any fatality occur in the Company's workforce (including its Contractors) or any material event occurs which constitutes a breach of Karoon's Anti-bribery and Corruption Policy.

Based on actual results, in respect of the current Chief Executive Officer and Managing Director, a total of 67.5% of the available STI opportunity, payable 50% in cash and 50% via a grant of performance rights (with such performance rights subject to a one year employment retention), satisfied the requisite STI performance targets outlined above. For other KMP, between 74% and 77.3% of the available STI opportunity satisfied requisite performance targets (based on the results of role-specific performance targets).

Performance rights (associated with the STI) that have satisfied requisite performance hurdles have a 1-year retention period ending 30 June 2023 before they become exercisable and convertible into fully paid ordinary shares. These STI performance rights expire on 30 June 2024.

Remuneration Report (Audited) Continued

Section 3. Executive Remuneration Continued

LTI Outcomes

Karoon's 2020 LTI performance conditions of achieving an absolute total shareholder return ('TSR') of 14% per annum and a minimum 50th percentile against the Company's Relative TSR when compared with a select group of peer companies over the period from 1 July 2019 to 30 June 2022 was met. Karoon was at the 100th percentile when compared against the relevant industry peer group and, accordingly, 100% of the 2020 LTI entitlement vested.

Voluntary Information: 2022 'Remuneration Received'

The amounts disclosed below reflect the actual benefits received by each executive during the financial year ended 30 June 2022 and have been translated into US$ from local currencies using the average exchange rate for the 2022 financial year. The average rate used for A$/US$ was 0.7259 and BRL/US$ was 0.1909. The amounts disclosed below include the actual value of any equity-settled and/or cash-settled award received from STI and/or LTI.

The amounts disclosed in the table below are not the same as the statutory remuneration expensed in relation to each executive in accordance with Australian Accounting Standards shown in the statutory table in Section 5 of the Remuneration Report. The remuneration values disclosed below have been determined as follows:

Fixed Remuneration

Fixed remuneration includes cash salary and fees, non-monetary benefits, superannuation contributions and paid long service leave.

Fixed remuneration excludes any accruals of annual or long service leave.

Cash Bonus

Includes one-off cash bonuses paid to executives who ceased employment and sign-on cash bonuses paid to executives who commenced during the period.

Short-term Incentives

Includes cash bonuses and the equity-settled and/or cash-settled award received from STI by executives, subject to achievement of performance conditions. The value of STI equity-settled and cash-settled awards received reflects the amounts disclosed to the relevant tax authorities during the financial year ended 30 June 2022.

Long-term Incentives

Includes the equity-settled and/or cash-settled award received from LTI by executives. The value of LTI equity-settled awards and cash-settled awards received reflects the amounts disclosed to the relevant tax authorities during the financial year ended 30 June 2022.

	FIXED REMUNER-ATION US$	CASH BONUS US$	SHORT-TERM INCENTIVES US$	LONG-TERM INCENTIVES US$	TERMINATION BENEFIT US$	TOTAL REMUNER-ATION RECEIVED US$
Executive Directors						
Dr Julian Fowles	614,626	–	–	–	–	614,626
Other KMP (Group)				–		
Mr Ray Church (commenced on 27 September 2021)	371,339	72,590	–	–	–	443,929
Mr Antonio Guimarães (commenced on 1 October 2021)	265,400	108,831	–	–	–	374,231
Mr Scott Hosking (ceased as Chief Financial Officer on 30 September 2021)	207,467	42,737	–	–	151,713	401,917
Mr Edward Munks (ceased as Chief Operating Officer on 30 September 2021)	305,939	90,061	–	–	284,462	680,462
Mr Ricardo Abi-Ramia (ceased as KMP on 1 October 2021)	66,110	–	–	–	–	66,110

The Board of Directors believes that 'remuneration received' is more relevant to shareholders for the following reasons:

- the statutory remuneration expensed through as share-based payments (ESOP options and/or performance rights) is based on historic cost and does not reflect the value of equity-settled and/or cash-settled amounts when they are actually received;
- the statutory remuneration shows benefits before they are actually received by executives;
- where ESOP options or performance rights do not vest because a market-based performance condition is not satisfied (for example, an increase in Karoon's share price), Karoon must still recognise the full amount of the share-based payments expense even though the executives do not receive the benefit; and
- share-based payment awards are treated differently under Australian Accounting Standards depending on whether the performance conditions are market conditions (no reversal of share-based payments expense) or non-market conditions (reversal of share-based payments expense when ESOP options or performance rights fail to vest), even though the benefit received by the executive is the same ($Nil where the ESOP option or performance right fail to vest).

The information in this section has been audited together with the rest of the Remuneration Report.

C. Executive Agreements

Remuneration and other terms of employment for the executives are formalised in employment agreements. Each of these agreements provide for participation, when eligible, in the Company's PRP. Other major provisions of the agreements relating to remuneration are set out below.

Termination payments for executives, if any, are agreed by the Board and/or People, Culture and Governance Committee in advance of employment and stated in the relevant employment agreements. Upon retirement, executives are paid employee benefit entitlements accrued to the date of retirement.

Details of existing employment agreements between the Company and the Executive Director and other KMP are as follows:

NAME	TERM	EXPIRY	NOTICE/ TERMINATION PERIOD	TERMINATION PAYMENTS	PERFORMANCE RIGHT ELIGIBLE
Executive Directors					
Dr Julian Fowles	From 27 November 2020, ongoing	Ongoing	In writing six months	Not applicable.	Yes
Other KMP					
Mr Ray Church	From 27 September 2021, ongoing	Ongoing	In writing six months	Not applicable.	Yes
Mr Antonio Guimarães	From 1 October 2021, ongoing	Ongoing	In accordance with Brazilian labour legislation	Not applicable (statutory entitlements).	Yes
Mr Ricardo Abi-Ramia	Ongoing	Ongoing	In writing one month	Not applicable (statutory entitlements).	Yes

All termination payments for Australian employees are subject to the limits prescribed under Section 200B of the *Corporations Act 2001*.

The employment agreements of executives are on a continuing basis, the terms of which are not expected to change in the immediate future.

DIRECTORS' REPORT CONTINUED

Remuneration Report (Audited) Continued

Section 4. Independent Non-Executive Chairman and Non-Executive Directors

Fees and payments to the independent Non-Executive Chairman and other Non-Executive Directors reflect the demands, which are placed on, and the responsibilities of the Directors of Karoon. The Company reviews Independent Non-Executive Chairman and other Non-Executive Director remuneration annually and assesses the change to the Company's activities and overall responsibilities of each Non-Executive Director.

There have been no changes to Non-Executive Directors' base or individual committee fees during the course of the financial year ending 30 June 2022. The table at the end of this section provides a summary of Karoon's Non-Executive Director fee policy for the 2022 financial year.

Non-Executive Director fees are determined within an aggregate Directors' fee pool limit, which is periodically approved by shareholders. The maximum aggregate amount, including superannuation contribution, that may be paid to Non-Executive Directors of the Company as remuneration for their services per annum is A$1,200,000, as approved by shareholders at the Company's 2015 Annual General Meeting. For the financial year ended 30 June 2022, the total fees paid to Non-Executive Directors was A$835,000.

Superannuation contributions are paid, in accordance with Australian superannuation guarantee legislation, on Directors' fees paid to Australian resident Non-Executive Directors.

Share-based Remuneration

Non-Executive Directors do not ordinarily receive performance-related remuneration. The Company has determined that it will not grant bonus or incentive related share-based remuneration to Non-Executive Directors. Non-Executive Directors will continue to be encouraged to purchase ordinary shares in the Company on-market in accordance with the Director Minimum Shareholding Policy.

Retirement Allowance for Directors

Karoon does not provide any Non-Executive Director with a retirement allowance.

Non-Executive Director Fees for the Financial Year Ended 30 June 2022

Non-Executive Directors' fees for the financial year ended 30 June 2022 (excluding superannuation contribution) are outlined in the following table:

Base fee	
Non-Executive Chairman*	A$220,000
Non-Executive Directors	A$100,000
Committee member fees	
Audit and Risk Committee	
Chairman	A$25,000
Member	A$20,000
People, Culture and Governance Committee	
Chairman	A$20,000
Member	A$15,000
Sustainability and Operational Risk Committee	
Chairman	A$20,000
Member	A$15,000

* Non-Executive Chairman base fee includes compensation for the appointment to relevant Committees.

Section 5. Statutory and Share-based Reporting

Details of the Remuneration of the Directors and Other Key Management Personnel

Details of the remuneration of the Directors and other KMP of the Group for the financial year and previous financial year are set out in the following tables. For all remuneration reporting stated in US$, exchange rates of AU$/US$ 0.7259 (2021: 0.7472) and BRL/US$ 0.1909 (2021: 0.1857) have been used.

FINANCIAL YEAR ENDED 30 JUNE 2022	SHORT-TERM BENEFITS			POST-EMPLOYMENT BENEFITS		LONG-TERM BENEFITS		SHARE-BASED PAYMENTS EXPENSE		
NAME	BASE SALARY AND FEES US$	NON-MONETARY BENEFITS US$	CASH STI/ BONUS US$	SUPER-ANNUATION CONTRIB-UTIONS US$	SOCIAL SECURITY & INDEMNITY FUND CONTRIB-UTIONS US$	LONG SERVICE LEAVE US$	TERMINATION PAYMENTS US$	SHARE OPTIONS/ PERFORM-ANCE RIGHTS US$	REMUNER-ATION CONSISTING OF SHARE OPTIONS/ PERFORM-ANCE RIGHTS* %	TOTAL REMUNER-ATION US$
Executive Directors										
Dr Julian Fowles	561,302	–	156,176	53,324	–	3,253	–	513,533	39.9	1,287,588
Non-Executive Directors										
Mr Bruce Phillips	159,698	–	–	15,970	–	–	–	–	–	175,668
Ms Luciana Rachid	87,108	–	–	–	–	–	–	–	–	87,108
Mr Clark Davey	101,626	–	–	10,163	–	–	–	–	–	111,789
Mr Peter Turnbull	112,515	–	–	11,251	–	–	–	–	–	123,766
Mr Peter Botten	97,997	–	–	9,800	–	–	–	–	–	107,797
Total Directors' remuneration	1,120,246	–	156,176	100,508	–	3,253	–	513,533		1,893,716
Other KMP (Group)										
Mr Ray Church (commenced as EVP and Chief Financial Officer on 27 September 2021)	327,493	29,590	193,164	14,257	–	508	–	162,454	22.3	727,466
Mr Antonio Guimarães (commenced as EVP and President Karoon Brazil on 1 October 2021)	187,518	13,879	180,428	–	64,003	–	–	92,229	17.1	538,057
Mr Scott Hosking (ceased as Chief Financial Officer on 30 September 2021)	136,305	5,564	42,737	12,831	–	(1,105)	151,713	1,063,712^	75.3	1,411,757
Mr Edward Munks (ceased as Chief Operating Officer on 30 September 2021)	228,299	–	90,061	12,831	–	1,408	284,462	410,829^	40.0	1,027,890
Mr Ricardo Abi-Ramia (ceased as KMP on 1 October 2021)	47,084	2,406	9,732	–	16,620	–	–	64,680	46.0	140,522
Total other KMP remuneration (Group)	926,699	51,439	516,122	39,919	80,623	811	436,175	1,793,904		3,845,692
Total KMP remuneration (Group)	2,046,945	51,439	672,298	140,427	80,623	4,064	436,175	2,307,437		5,739,408

* The percentage of total remuneration consisting of share options and performance rights, based on the value of share options and performance rights expensed in the consolidated statement of profit or loss and other comprehensive income during the financial year.

^ Scott Hosking and Edward Munks share-based payments expense includes accelerated vesting of STI and LTI for accounting purposes, which they retained on cessation of their employment with the Company.

Remuneration Report (Audited) Continued

Section 5. Statutory and Share-based Reporting Continued

FINANCIAL YEAR ENDED 30 JUNE 2021	SHORT-TERM BENEFITS			POST-EMPLOYMENT BENEFITS		LONG-TERM BENEFITS		SHARE-BASED PAYMENTS EXPENSE		
NAME	BASE SALARY AND FEES US$	NON-MONETARY BENEFITS US$	CASH STI/ BONUS US$	SUPER-ANNUATION CONTRIB-UTIONS US$	SOCIAL SECURITY & INDEMNITY FUND CONTRIB-UTIONS US$	LONG SERVICE LEAVE US$	TERMINATION PAYMENTS US$	SHARE OPTIONS/ PERFORM-ANCE RIGHTS US$	REMUNER-ATION CONSISTING OF SHARE OPTIONS PERFORM-ANCE RIGHTS* %	TOTAL REMUNER-ATION US$
Executive Directors										
Dr Julian Fowles (commenced as Director on 27 November 2020)	331,211	–	37,262	31,465	–	310	–	102,548	20.4	502,796
Mr Robert Hosking (retired as a Director on 27 November 2020)	277,343	23,818	112,080	16,210	–	7,735	–	455,034^	51.0	892,220
Non-Executive Directors										
Mr Bruce Phillips	153,425	–	–	15,616	–	–	–	–	–	169,041
Ms Luciana Rachid	83,686	–	–	–	–	–	–	–	–	83,686
Mr Geoff Atkins (retired as a Director on 27 November 2020)	35,305	–	–	3,993	–	–	–	–	–	39,298
Mr Clark Davey	97,634	–	–	9,938	–	–	–	–	–	107,572
Mr Peter Turnbull	108,095	–	–	11,003	–	–	–	–	–	119,098
Mr José Coutinho Barbosa (retired as a Director on 27 November 2020)	30,075	–	–	–	–	–	–	–	–	30,075
Mr Peter Botten (commenced as a Director on 1 October 2020)	71,295	–	–	6,773	–	–	–	–	–	78,068
Total Directors' remuneration	**1,188,069**	**23,818**	**149,342**	**94,998**	**–**	**8,045**	**–**	**557,582**		**2,021,854**
Other KMP (Group)										
Mr Scott Hosking	291,508	12,756	44,832	16,210	–	4,683	–	603,040	62.0	973,029
Mr Tim Hosking (ceased as South American General Manager and Chief Executive Officer Brazil on 31 March 2021)	201,442	15,207	23,643	–	29,798	–	469,609	1,161,031^	61.1	1,900,730
Mr Edward Munks	364,385	1,531	22,416	16,210	–	4,833	–	403,554	49.6	812,929
Mr Ricardo Abi-Ramia (commenced as Senior VP Operations from 31 March 2021)	49,522	1,778	–	–	17,481	–	–	39,735	36.6	108,516
Total other KMP remuneration (Group)	**906,857**	**31,272**	**90,891**	**32,420**	**47,279**	**9,516**	**469,609**	**2,207,360**		**3,795,204**
Total KMP remuneration (Group)	**2,094,926**	**55,090**	**240,233**	**127,418**	**47,279**	**17,561**	**469,609**	**2,764,942**		**5,817,058**

* The percentage of total remuneration consisting of share options and performance rights, based on the value of share options and performance rights expensed in the consolidated statement of profit or loss and other comprehensive income during the financial year.

^ Robert Hosking and Tim Hosking's share-based expense includes the accelerated vesting of STI and LTI for accounting purposes, which they retained on cessation of their employment with the Company.

The amounts disclosed for the remuneration of Directors and other KMP include the assessed fair values of performance rights granted during the financial year, at the date they were granted, with the exception of cash-settled share-based payments which are revalued at year end and performance rights for the FY2022 award, where the fair value is equivalent to the STI opportunity achieved based on a percentage of fixed remuneration or base salary. Performance rights for the FY2022 award will be granted following the release of the Company's 2022 full year results. The value attributable to share options and performance rights is allocated to particular financial periods in accordance with AASB 2 *'Share-based Payment'*, which requires the value of a share option and performance right at grant date to be allocated equally over the period from grant date to vesting date, adjusted for not meeting the vesting condition. For share options and performance rights that vest immediately, the value is disclosed as remuneration immediately, in accordance with the accounting policy described in Note 1(s) of the consolidated financial statements. In addition, acceleration of vesting occurs for share options and performance rights up to the end of an employee's respective service period, where the options and rights are retained post cessation of employment.

Fair value of share options is assessed under the Black-Scholes option pricing model. The Black-Scholes option pricing model considers the exercise price, the term of the share option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the share option. With the exception of long-term performance rights granted during the current financial year, the fair value of performance rights were based on the Company's closing share price at grant date. Long-term performance rights granted during the current financial year, which are subject to market-based performance conditions, have been valued using a Monte Carlo simulation approach.

Remuneration Report (Audited) Continued

Section 5. Statutory and Share-based Reporting Continued

The relative percentage proportions of remuneration that are linked to performance conditions, those that are not and those that are fixed are as follows:

					NOT RELATED TO PERFORMANCE CONDITIONS		RELATED TO PERFORMANCE CONDITIONS							
	FIXED REMUNERATION		TERMINATION PAYMENTS		CASH BONUS		CASH BONUS		STI (PERFORMANCE RIGHTS)		LTI (PERFORMANCE RIGHTS)		LTI (SHARE OPTIONS)	
NAME	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021
Executive Director														
Dr Julian Fowles	**48.0%**	72.2%	**–**	–	**–**	–	**12.1%**	7.4%	**3.7%**	–	**36.2%**	20.4%	**–**	–
Non-Executive Directors														
Mr Bruce Phillips	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Ms Luciana Rachid	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Mr Clark Davey	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Mr Peter Turnbull	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Mr Peter Botten	**100%**	100%	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–
Other KMP (Group)														
Mr Ray Church (commenced as EVP and Chief Financial Officer on 27 September 2021)	**51.1%**	–	**–**	–	**10.0%**	–	**16.6%**	–	**14.0%**	–	**8.3%**	–	**–**	–
Mr Antonio Guimarães (commenced as EVP and President Karoon Brazil on 1 October 2021)	**49.3%**	–	**–**	–	**20.2%**	–	**13.3%**	–	**10.5%**	–	**6.7%**	–	**–**	–
Mr Scott Hosking (ceased as Chief Financial Officer on 30 September 2021)	**10.9%**	33.4%	**10.7%**	–	**–**	–	**3.0%**	4.6%	**19.5%**	20.8%	**51.4%**	34.3%	**4.5%**	6.9%
Mr Edward Munks (ceased as Chief Operating Officer on 30 September 2021)	**23.6%**	47.6%	**27.6%**	–	**–**	–	**8.8%**	2.8%	**11.8%**	16.0%	**28.2%**	29.2%	**–**	4.4%
Mr Ricardo Abi-Ramia (ceased as KMP on 1 October 2021)	**47.1%**	63.4%	**–**	–	**–**	–	**6.9%**	–	**9.6%**	13.2%	**19.8%**	21.6%	**16.6%**	1.8%

Further information on share options and performance rights is set out in Note 31 of the consolidated financial statements.

Amounts disclosed for remuneration of Directors and other KMP exclude insurance premiums paid by the Company in respect of directors' and officers' liability insurance contracts, as the contracts do not specify premiums paid in respect of individual Directors and officers. Information relating to insurance contracts is set out in this Directors' Report.

Share-based Remuneration

As at 30 June 2022, there were 13,645,295 performance rights issued under the 2016 PRP and 2019 PRP respectively, representing approximately 2.45% of the Company's total number of shares issued. Subsequent to year end, 3,129,151 performance rights have vested and converted to ordinary shares as outlined on page 46.

The terms and conditions of each grant of performance rights over unissued ordinary shares in the Company affecting remuneration in the current or a future financial year are as follows:

GRANT DATE	DATE VESTED AND EXERCISABLE	EXPIRY DATE	EXERCISE PRICE PER SHARE OPTION OR PERFORMANCE RIGHT	FAIR VALUE PER SHARE OPTION OR PERFORMANCE RIGHT AT GRANT DATE	% VESTED	PERFORMANCE CONDITION ACHIEVED
Performance rights						
12 November 2019	1 July 2022	30 June 2023	$–	A$1.060	100	2022 Performance Condition
18 October 2019	1 July 2022	30 June 2023	$–	A$1.075	100	2022 Performance Condition
29 November 2019	1 July 2022	30 June 2023	$–	A$1.115	100	2022 Performance Condition
25 September 2020	1 July 2022	30 June 2023	$–	A$0.740	69	2021 Performance Condition
25 September 2020	1 July 2023	30 June 2024	$–	A$0.587	–	To be determined
27 November 2020	1 July 2023	30 June 2024	$–	A$1.572	–	To be determined
23 March 2022	1 July 2024	30 June 2025	$–	A$1.815	–	To be determined
6 May 2022	1 July 2024	30 June 2025	$–	A$1.525	–	To be determined

Performance rights are granted for no consideration. Performance rights granted carry no dividend or voting rights.

Number of Performance Rights Provided as Remuneration During the Financial Year

Details of performance rights over unissued ordinary shares in the Company provided as remuneration to each Director and each of the other KMP, including their personally related parties, are set out below:

NAME	NUMBER OF PERFORMANCE RIGHTS GRANTED DURING FINANCIAL YEAR	FAIR VALUE PER PERFORMANCE RIGHT AT GRANT DATE*	VALUE OF PERFORMANCE RIGHTS AT GRANT DATE*	NUMBER OF PERFORMANCE RIGHTS VESTED DURING FINANCIAL YEAR	NUMBER OF PERFORMANCE RIGHTS FORFEITED	VALUE OF PERFORMANCE RIGHTS FORFEITED**
Executive Directors						
Dr Julian Fowles						
– Performance rights (LTI)	577,052	A$1.525	A$880,004	–	–	–
Other key management personnel (Group)						
Mr Ray Church						
– Performance rights (LTI)	276,389	A$1.525	A$421,493	–	–	–
Mr Antonio Guimarães						
– Performance rights (LTI)	152,660	A$1.525	A$232,807	–	–	–
Mr Ricardo Abi-Ramia						
– Performance rights (STI)	–	–	–	84,060	51,395	A$70,411
– Performance rights (LTI)	79,674	A$1.815	A$144,608	–	–	–
Total key management personnel						
– Performance rights	1,085,775		A$1,678,912	84,060	51,395	A$70,411

* The value at grant date, calculated in accordance with AASB 2, of share options and performance rights granted during the financial year as part of their remuneration.

** The value of performance rights forfeited during the financial year because a vesting condition was not satisfied was determined at the time of forfeit (7 July 2021), but assuming the condition was satisfied, based on the underlying value of the share options or performance rights at that date.

No share options or performance rights over unissued ordinary shares in the Company, held by any Director or other KMP, lapsed during the financial year, except for 51,395 performance rights that were forfeited by Directors and other KMP.

DIRECTORS' REPORT CONTINUED

Remuneration Report (Audited) Continued

Section 5. Statutory and Share-based Reporting Continued

Shares Issued on the Exercise of Share Options Provided as Remuneration

No share options were exercised by any Director or other KMP, including their personally related parties, during the financial year.

Shares Issued on the Conversion of Performance Rights Provided as Remuneration

Details of fully paid ordinary shares in the Company issued, as a result of the exercise and conversion of remuneration performance rights to each Director and other KMP, during the financial year, including their personally related parties, are set out below:

NAME	DATE OF CONVERSION OF PERFORMANCE RIGHTS	NUMBER OF ORDINARY SHARES ISSUED	VALUE AT CONVERSION DATE*	AMOUNT PAID PER PERFORMANCE RIGHT
Other KMP (Group)				
Mr Ricardo Abi-Ramia	7 September 2021	84,060	A$100,872	$–
		84,060	**A$100,872**	

* The value at conversion date of performance rights that were granted as part of their remuneration and were converted during the financial year has been determined as the underlying value of the performance rights at that date.

No amounts are unpaid on any ordinary shares issued on the conversion of the above remuneration performance rights.

Details of Remuneration – Share Options and Performance Rights

For each grant of share options or performance rights in current or previous financial years which resulted in a share-based payment expense to Directors and other KMP, the percentage of the grant that vested and percentage that was forfeited because the individual did not meet the service and/or pre-determined performance conditions is set out below:

NAME	FINANCIAL YEAR END GRANTED	VESTED %	FORFEITED %	FINANCIAL YEARS IN WHICH SHARE OPTIONS OR PERFORMANCE RIGHTS MAY VEST	MAXIMUM TOTAL VALUE OF GRANT YET TO VEST US$
Executive Director					
Dr Julian Fowles					
– Performance rights (LTI)	30 June 2021	–	–	30 June 2024	221,513
– Performance rights (LTI)	30 June 2022	–	–	30 June 2025	425,447
– Performance rights (STI)*	30 June 2023	–	–	30 June 2024	47,360
Other KMP (Group)					
Mr Ray Church					
– Performance rights (LTI)	30 June 2022	–	–	30 June 2025	203,775
– Performance rights (STI)*	30 June 2023	–	–	30 June 2024	60,287
Mr Antonio Guimarães					
– Performance rights (LTI)	30 June 2022	–	–	30 June 2025	112,553
– Performance rights (STI)*	30 June 2023	–	–	30 June 2024	35,798
Mr Ricardo Abi-Ramia					
– Performance rights (LTI)	30 June 2020	100	–	30 June 2023	–
– Performance rights (STI)	30 June 2021	73.3	26.7	30 June 2023	–
– Performance rights (LTI)	30 June 2021	–	–	30 June 2024	30,188
– Performance rights (LTI)	30 June 2022	–	–	30 June 2025	69,928
– Performance rights (STI)*	30 June 2023	–	–	30 June 2024	19,517
Mr Edward Munks					
– Performance rights (LTI)	30 June 2020	100	–	30 June 2023	–
– Performance rights (STI)	30 June 2021	63.2	36.8	30 June 2023	–
– Performance rights (LTI)	30 June 2021	–	–	30 June 2024	–
Mr Scott Hosking					
– Performance rights (LTI)	30 June 2020	100	–	30 June 2023	–
– Performance rights (STI)	30 June 2021	63.2	36.8	30 June 2023	–
– Performance rights (LTI)	30 June 2021	–	–	30 June 2024	–

* Performance rights for the deferred portion of the FY2022 award will be granted following the release of the Company's 2022 full year results. The number of performance rights will depend on the Company's weighted average share price in the 20-trading day period after the release of the Company's 2022 full year financial results.

No share options or performance rights will vest if the service and/or pre-determined performance conditions are not met, therefore the minimum value of the share option or performance right yet to vest is $Nil.

The maximum value of share options and performance rights yet to vest was determined as the amount of the grant date fair value of the share options or performance rights that is yet to be expensed in the consolidated statement of profit or loss and other comprehensive income. For the FY2022 award, the maximum value yet to vest is equivalent to the STI opportunity achieved, based on a percentage of fixed remuneration or base salary, to be expensed over the remaining vesting period.

Share Options and Performance Rights over Unissued Ordinary Shares in the Company as at 30 June 2022

During the financial year 1,085,775 performance rights over unissued ordinary shares in the Company were issued to Directors and other KMP, including their personally related parties.

The movement of share options and performance rights over unissued ordinary shares in the Company held by Directors and other KMP, including their personally related parties, during the financial year was as follows:

	BALANCE AS AT 1 JULY 2021	GRANTED AS REMUNERATION	EXERCISED SHARE OPTIONS/ VESTED AND CONVERTED PERFORMANCE RIGHTS	CASH-SETTLED	SHARE OPTIONS OR PERFORMANCE RIGHTS FORFEITED	OTHER	BALANCE AS AT 30 JUNE 2022	TOTAL VESTED AND EXERCISABLE AS AT 30 JUNE 2022	TOTAL UNVESTED AS AT 30 JUNE 2022
Executive Director									
Dr Julian Fowles									
– Performance rights	502,989	577,052	–	–	–	–	1,080,041	–	1,080,041
Non-Executive Directors									
Mr Bruce Phillips	–	–	–	–	–	–	–	–	–
Ms Luciana Rachid	–	–	–	–	–	–	–	–	–
Mr Clark Davey	–	–	–	–	–	–	–	–	–
Mr Peter Turnbull	–	–	–	–	–	–	–	–	–
Mr Peter Botten	–	–	–	–	–	–	–	–	–
Other KMP									
Mr Ray Church									
– Performance rights	–	276,389	–	–	–	–	276,389	–	276,389
Mr Antonio Guimarães									
– Performance rights	–	152,660	–	–	–	–	152,660	–	152,660
Mr Scott Hosking									
– ESOP options	369,258	–	–	–		(369,258)[1]	–		–
– Performance rights	1,447,130	–	–	–	(170,915)	(1,276,215)[1]	–		–
Mr Edward Munks									
– ESOP options	461,572	–	–	–	–	(461,572)[1]	–		–
– Performance rights	1,808,916	–	–	–	(213,645)	(1,595,271)[1]	–		–
Mr Ricardo Abi-Ramia									
– ESOP options	258,138	–	–	–	–	(258,138)[2]	–		–
– Performance rights	692,353	79,674	(84,060)	–	(51,395)	(636,572)[2]	–		–
Total key management personnel									
– Share options	1,088,968	–	–	–	–	(1,088,968)	–	–	–
– Performance rights	4,451,388	1,085,775	(84,060)	–	(435,955)	(3,508,058)	1,509,090	–	1,509,090

1. Reflects Scott Hosking's and Ed Munks' respective holdings, held both individual and by personally related parties, when they ceased to be employees on 30 September 2021.
2. Reflects Ricardo Abi-Ramia holdings when he ceased to be a KMP on 1 October 2021.

All performance rights granted during the financial year were issued under the 2019 PRP.

Remuneration Report (Audited) Continued

Section 5. Statutory and Share-based Reporting Continued

The number of ordinary shares held by Directors and other KMP, including their personally related parties, as at 30 June 2022 was as follows:

	BALANCE AS AT 1 JULY 2021	RECEIVED AS REMUNER-ATION	EXERCISED (SHARE OPTIONS)/ VESTED AND CONVERTED (PERFORM-ANCE RIGHTS)	SHARES PURCHASED	ORDINARY SHARES SOLD	OTHER^	BALANCE AS AT 30 JUNE 2022
Executive Director							
Dr Julian Fowles	107,659	–	–	–	–	–	107,659
Non-Executive Directors							
Mr Bruce Phillips	1,750,000	–	–	–	–	–	1,750,000
Mr Clark Davey	147,214	–	–	–	–	–	147,214
Mr Peter Turnbull	146,269	–	–	–	–	–	146,269
Ms Luciana Rachid	52,960	–	–	–	–	–	52,960
Mr Peter Botten	–	–	–	–	–	–	–
Other KMP							
Mr Ray Church (commenced as EVP and Chief Financial Officer on 27 September 2021)	–	–	–	–	–	–	–
Mr Antonio Guimarães (commenced as EVP and President Karoon Brazil on 1 October 2021)	–	–	–	–	–	–	–
Mr Scott Hosking (ceased as Chief Financial Officer on 30 September 2021)	614,634	–	–	–	(19,204)	(595,430)	–
Mr Edward Munks (ceased as Chief Operating Officer on 30 September 2021)	1,114,932	–	–	–	–	(1,114,932)	–
Mr Ricardo Abi-Ramia (ceased as KMP on 1 October 2021)	173,402	–	84,060	–	–	(257,462)	–
Total KMP	**4,107,070**	**–**	**84,060**	**–**	**(19,204)**	**(1,967,824)**	**2,204,102**

^ Other reflects the respective other KMP shareholdings (held both individually and by personally related parties) when they either commenced or ceased their role as a KMP during the year.

None of the ordinary shares are held nominally by any Director or any of the other key management personnel. 'Held nominally' refers to the situation where the ordinary shares are in the name of the Director or other key management person, but he is not the beneficial owner.

Other Transactions with Directors and Other KMP

A formal Related Party Protocol requires the approval by the People, Culture and Governance Committee and, thereafter, the Board of Directors of all new related party transactions.

There were no related party transactions with Directors or other KMP during the financial year.

Loans to Directors and Other KMP

There were no loans to Directors or other KMP during the financial year.

Rounding

The amounts in the financial report are rounded to the nearest thousand dollars (US$'000) unless otherwise indicated, under the option available to the Company under ASIC Corporations (Rounding in Financial/Directors Reports) Instrument 2016/191. The Company is an entity to which this legislative instrument applies.

This Directors' Report, incorporating the Remuneration Report, is made in accordance with a resolution of the Directors.

On behalf of the Directors:

Mr Bruce Phillips
Independent Non-Executive Chairman

Dr Julian Fowles
Chief Executive Officer and Managing Director

25 August 2022

AUDITOR'S INDEPENDENCE DECLARATION

Auditor's Independence Declaration

As lead auditor for the audit of Karoon Energy Ltd for the year ended 30 June 2022, I declare that to the best of my knowledge and belief, there have been:

(a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit, and

(b) no contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Karoon Energy Ltd and the entities it controlled during the period.

Anthony Hodge
Partner
PricewaterhouseCoopers

Melbourne
25 August 2022

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CONSOLIDATED FINANCIAL STATEMENTS

For the Financial Year Ended 30 June 2022

Karoon Energy Ltd (the 'Company') is a public company limited by shares and is listed on the ASX. It is incorporated and domiciled in Australia.

The registered office and principal place of business of Karoon Energy Ltd is Suite 3.02, Level 3, 6 Riverside Quay, Southbank VIC 3006.

The consolidated financial statements are for the consolidated entity consisting of the Company and its subsidiaries.

The consolidated financial statements are presented in United States dollars.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

For the Financial Year Ended 30 June 2022

		CONSOLIDATED	
	NOTE	2022 US$'000	2021 US$'000
Revenue	4(a)	**385,074**	170,809
Cost of Sales	5(a)	**(191,704)**	(111,375)
Gross Profit		**193,370**	59,434
Other income	4(b)	**789**	305
Business development and transition costs	5(b)	**(3,362)**	(17,564)
Exploration expenses	5(c)	**(3,196)**	(3,416)
Finance costs	5(d)	**(22,709)**	(14,401)
Net foreign currency gains/(losses)		**6,203**	(17,053)
Other expenses	5(e)	**(33,814)**	(28,546)
Change in fair value of contingent consideration	23(ii)	**(227,119)**	(6,632)
Loss before income tax		**(89,838)**	(27,873)
Income tax benefit	6	**25,387**	32,257
Profit (Loss) for financial year attributable to equity holders of the Company		**(64,451)**	4,384
Other comprehensive income, net of income tax:			
Items that may be reclassified subsequently to profit or loss			
Exchange differences arising from the translation of financial statements into presentation currency		**(4,332)**	13,493
Net change in fair value of cash flow hedges and cost of hedging	24(d)	**(41,274)**	–
Other comprehensive income (loss) for financial year, net of income tax		**(45,606)**	13,493
Total comprehensive income (loss) for financial year attributable to equity holders of the Company, net of income tax		**(110,057)**	17,877
Profit (Loss) per share attributable to equity holders of the Company:			
Basic profit (loss) per ordinary share	9	**(0.1159)**	0.0079
Diluted profit (loss) per ordinary share	9	**(0.1159)**	0.0077

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at 30 June 2022

	NOTE	CONSOLIDATED 2022 US$'000	2021 US$'000
Current assets			
Cash and cash equivalents	10	**157,683**	133,209
Receivables	11	**56,336**	34,162
Inventories	12	**19,403**	10,952
Security deposits	13	**325**	209
Other assets	14	**11,792**	5,317
Total current assets		245,539	183,849
Non-current assets			
Deferred tax assets	6	**122,982**	36,528
Inventories	12	**5,828**	6,536
Oil and gas assets	15	**733,042**	736,422
Property, plant and equipment	16	**13,257**	8,260
Intangible assets	17	**40**	102
Exploration and evaluation expenditure carried forward	18	**40,837**	40,853
Security deposits	13	**1,337**	1,406
Other assets	14	**1,277**	–
Total non-current assets		918,600	830,107
Total assets		1,164,139	1,013,956
Current liabilities			
Trade and other payables	19	**68,302**	76,174
Current tax liabilities		**9,597**	8,253
Other financial liabilities	23	**125,398**	–
Lease liabilities	21	**43,741**	45,393
Provisions	20	**368**	457
Total current liabilities		247,406	130,277
Non-current liabilities			
Trade and other payables	19	**6,763**	4,261
Borrowings	22	**27,144**	–
Other financial liabilities	23	**221,994**	71,161
Deferred tax liabilities	6	**–**	1,775
Lease liabilities	21	**245,146**	267,447
Provisions	20	**139,485**	158,785
Total non-current liabilities		640,532	503,429
Total liabilities		887,938	633,706
Net assets		276,201	380,250
Equity			
Contributed equity	24	**907,514**	905,138
Accumulated losses		**(478,816)**	(414,365)
Reserves		**(152,497)**	(110,523)
Total equity		276,201	380,250

The above consolidated statement of financial position should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the Financial Year Ended 30 June 2022

		CONSOLIDATED					
	NOTE	CONTRIBUTED EQUITY US$'000	ACCUMULATED LOSSES US$'000	SHARE-BASED PAYMENTS RESERVE US$'000	FOREIGN CURRENCY TRANSLATION RESERVE US$'000	HEDGING RESERVES US$'000	TOTAL EQUITY US$'000
Balance as at 1 July 2020		905,281	(418,749)	47,156	(174,206)	–	359,482
Profit for financial year		–	4,384	–	–	–	4,384
Other comprehensive income (loss)		–	–	–	13,493	–	13,493
Total comprehensive profit for financial year		–	4,384	–	13,493	–	17,877
Transactions with owners in their capacity as owners:							
Deferred tax adjustment on transaction costs arising on ordinary shares issued in prior period	24(b)	(143)	–	–	–	–	(143)
Share-based payments expense	31(e)	–	–	3,034	–	–	3,034
		(143)	–	3,034	–	–	2,891
Balance as at 30 June 2021		905,138	(414,365)	50,190	(160,713)	–	380,250
Profit (loss) for financial year		**–**	**(64,451)**	**–**	**–**	**–**	**(64,451)**
Other comprehensive income (loss)		**–**	**–**	**–**	**(4,332)**	**(41,274)**	**(45,606)**
Total comprehensive loss for financial year		**–**	**(64,451)**	**–**	**(4,332)**	**(41,274)**	**(110,057)**
Transactions with owners in their capacity as owners:							
Exercise of options	24(b)	**2,376**	**–**	**–**	**–**	**–**	**2,376**
Share-based payments expense	31(e)	**–**	**–**	**3,632**	**–**	**–**	**3,632**
		2,376	**–**	**3,632**	**–**	**–**	**6,008**
Balance as at 30 June 2022		**907,514**	**(478,816)**	**53,822**	**(165,045)**	**(41,274)**	**276,201**

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CASH FLOWS

For the Financial Year ended 30 June 2022

	NOTE	CONSOLIDATED 2022 US$'000	2021 US$'000
Cash flows from operating activities			
Receipts from customers		**362,926**	136,978
Payments to suppliers and employees		**(116,988)**	(56,461)
Net refunds for Peruvian VAT		**519**	4,247
Payments for exploration and evaluation expenditure expensed		**(3,524)**	(15,231)
Payments for Baúna transition expenditure		**–**	(15,941)
Payments for legal settlement		**(9,600)**	–
Payments for cash flow hedges		**(20,827)**	–
Interest received		**25**	263
Borrowing and other costs of finance paid		**(18,860)**	(13,246)
Income taxes paid		**(39,425)**	(10,823)
Net cash flows from operating activities	30(a)	**154,246**	29,786
Cash flows from investing activities			
Purchase of plant and equipment and computer software		**(5,059)**	(4,717)
Acquisition of oil and gas assets		**(43,588)**	(150,000)
Payments for oil and gas assets		**(59,640)**	(16,031)
Borrowing costs paid for qualifying assets		**(5,807)**	(191)
Payments for exploration and evaluation expenditure capitalised		**–**	(1,915)
Release/refund (payment) of security deposits		**(260)**	3,621
Proceeds from disposal of non-current assets		**1,403**	20
Net cash flows used in investing activities		**(112,951)**	(169,213)
Cash flows from financing activities			
Principal elements of lease payments		**(44,553)**	(23,411)
Proceeds from issue of ordinary shares		**2,376**	–
Proceeds from borrowings		**30,000**	–
Debt facility establishment costs		**(3,320)**	–
Net cash flows used in financing activities		**(15,497)**	(23,411)
Net increase (decrease) in cash and cash equivalents		**25,798**	(162,838)
Cash and cash equivalents at beginning of financial year		**133,209**	296,420
Effect of exchange rate changes on the balance of cash and cash equivalents held in foreign currencies		**(1,324)**	(373)
Cash and cash equivalents at end of financial year	10	**157,683**	133,209

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the Financial Year Ended 30 June 2022

Note 1. Significant Accounting Policies

The consolidated financial statements are for the consolidated entity consisting of the Company and its subsidiaries (the 'Group'). Information on the nature of the operations and principal activities of the Group are described in the Directors' Report.

The following is a summary of significant accounting policies adopted by the Group in the preparation of these consolidated financial statements. The accounting policies have been consistently applied to all the financial years presented, unless otherwise stated.

(a) Basis of Preparation

These general-purpose financial statements have been prepared in accordance with Australian Accounting Standards and Interpretations issued by the Australian Accounting Standards Board (the 'AASB') and the *Corporations Act 2001* (Cth). The Company is a for-profit entity for the purpose of preparing financial statements.

Rounding

The amounts in the financial statements are rounded to the nearest thousand dollars (US$'000) unless otherwise indicated, under the option available to the Company under ASIC Corporations (Rounding in Financial/Directors Reports) Instrument 2016/191. The Company is an entity to which this legislative instrument applies.

Historical Cost Convention

The consolidated financial statements have been prepared on an accrual basis under the historical cost convention as modified, when relevant, by the revaluation of selected financial assets and financial liabilities for which the fair value basis of accounting has been applied.

Significant Accounting Estimates, Assumptions and Judgements

The preparation of financial statements requires the use of certain significant accounting estimates. It also requires management to exercise its judgement in the process of applying Group accounting policies. The areas involving a high degree of judgement or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements are disclosed in Note 2.

Compliance with International Financial Reporting Standards

Compliance with Australian Accounting Standards ensures that the consolidated financial statements comply with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Climate Change

In preparing the financial statements, the impact of climate change and current climate-related legislation has been considered.

The impact of climate change is considered in the significant judgements in a number of areas in the financial statements not limited to:

- Impairment of oil and gas assets (refer Note 2(a)); and
- Provision for restoration (refer Note 2(c)).

The Group continues to monitor climate related policy and its impact on the financial statements.

New, Revised or Amended Australian Accounting Standards and Interpretations that are First Effective in the Current Reporting Period

The Group has adopted all of the new, revised and/or amended Australian Accounting Standards and Interpretations issued by the AASB that are relevant to its operations and effective for the financial year ended 30 June 2022.

New and revised Australian Accounting Standards and amendments thereof and Interpretations effective for the financial year include:

(i) Amendments to AASB 4 *'Insurance Contracts'*, AASB 7 *'Financial Instruments Disclosures'*, AASB 9 *'Financial Instruments'*, AASB 16 *'Leases'* AASB 139 *'Financial Instruments: Recognition and Measurement': Interest rate benchmark reform* and *Costs necessary to sell inventories*, and

(ii) Amendments to AASB 16 *'Leases'*: COVID-19 Related Rent Concessions.

The initial adoption of all of these new, revised and/or amended Australian Accounting Standards and Interpretations has not resulted in any changes to the Group's accounting policies and has had no effect on either the amounts reported for the current or previous years.

Early Adoption of Australian Accounting Standards

The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective.

(b) Basis of Consolidation

The consolidated financial statements incorporate the assets and liabilities of all subsidiaries of the Company as at 30 June 2022 and the results of all subsidiaries for the financial year then ended.

Subsidiaries are all entities (including special purpose entities) over which the Group has control. The Group controls an entity when the Group is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are deconsolidated from the date that control ceases.

Interests in subsidiaries are set out in Note 25.

All subsidiaries have a financial year end of 30 June, with the exception of: Karoon Petróleo & Gas Ltda; Karoon Peru Pty Ltd, Sucursal del Peru; and KEI (Peru Z38) Pty Ltd, Sucursal del Peru which have a financial year end of 31 December in accordance with relevant Brazilian and Peruvian tax and accounting regulations respectively.

Accounting policies of subsidiaries have been changed, where necessary, to ensure consistency with the policies applied by the Group.

Intercompany transactions, balances and unrealised gains on transactions between Group companies are eliminated on consolidation. Unrealised losses are also eliminated, unless the transaction provides evidence of the impairment of the asset transferred.

(c) Segment Information

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for assessing performance and in determining the allocation of resources of the operating segments, has been identified as the Group's Executive Management Team.

(d) Revenue

Revenue from contracts with customers is recognised when the performance obligations are considered met, which is when control of the products or services provided are transferred to the customer. Revenue is recognised at an amount that reflects the consideration the Group expects to be entitled to, net of goods and services tax or similar taxes.

Where part or all of the transaction is price variable, revenue is recognised only to the extent that it is highly probable that a significant reversal of revenue will not occur.

Oil sales

Performance obligations are satisfied when the control of oil is transferred to the customer at the despatch point to the offtake vessel. The transaction price for oil sales may not be finalised at the date the customer takes control of the product. In such cases, a provisional transaction price is used until a final transaction price can be determined. The difference between the provisional and the final transaction price is recognised at the point when the final price is determined.

Credit terms for crude cargoes are between 30 and 45 days.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 1. Significant Accounting Policies Continued

Interest Income

Interest income on financial assets at amortised cost calculated using the effective interest method is recognised in the statement of profit or loss and other comprehensive income as other income. Interest income is calculated by applying the effective interest rate to the gross carrying amount of the relevant financial asset, except for financial assets that subsequently become credit impaired. For credit-impaired financial assets the effective interest rate is applied to the net carrying amount of the financial asset (after deduction of the loss allowance).

(e) Foreign Currency Transactions and Balances

Functional and Presentation Currency

Items included in the financial statements of each of the Group's subsidiaries are measured using the currency of the primary economic environment in which the subsidiary or branch operates (the 'functional currency').

The functional currency of the Company is Australian dollars. The Group's Brazilian & Peruvian Branches have a functional currency of US$.

The presentation currency of the consolidated financial statements is US$.

Transactions and Balances

Foreign currency transactions are translated into the functional currency using the foreign exchange rates prevailing at the dates of the transactions. Foreign currency gains and losses resulting from the settlement of such transactions and from the translation at financial year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in the consolidated statement of profit or loss and other comprehensive income, except when they are attributable to part of the net investment in a foreign operation.

Non-monetary items measured at historical cost continue to be carried at the foreign exchange rate at the date of the transaction. Foreign exchange differences arising on the translation of non-monetary items are recognised directly in equity to the extent that the gain or loss is directly recognised in equity, otherwise foreign exchange differences are recognised in the consolidated statement of profit or loss and other comprehensive income.

Foreign exchange gains and losses are presented in the consolidated statement of profit or loss and other comprehensive income on a net basis within other income or expenses.

Group Companies

The results and financial position of entities within the Group that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities are translated at the foreign exchange rates prevailing at the end of each reporting period.
- income and expenses are translated at the average foreign exchange rates for the financial period (unless this is not a reasonable approximation of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions); and
- all resulting foreign exchange differences are recognised in other comprehensive income.

On consolidation, foreign exchange differences arising on translation of foreign currency financial statements are transferred directly to the foreign currency translation reserve in the consolidated statement of financial position. The relevant differences are recognised in the consolidated statement of profit or loss and other comprehensive income during the financial period when the investment in the entity is disposed.

(f) Income Taxes and Other Taxes

Current Tax

Current tax (expense) income is calculated by reference to the amount of income taxes payable or recoverable in respect of the taxable profit or loss for the financial period. It is calculated using income tax rates and tax laws that have been enacted or are substantively enacted by the end of each reporting period in the countries where the Company's subsidiaries operate and generate taxable income. Current tax for current and previous financial periods is recognised as a liability (or asset) to the extent that it is unpaid or refundable.

Deferred Tax

Deferred tax is accounted for using the statement of financial position liability method in respect of temporary differences arising between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes. The tax base of an asset or liability is the amount attributed to that asset or liability for income taxation purposes.

No deferred tax is recognised from the initial recognition of an asset or liability, excluding a business combination, where there is no effect on accounting or taxable profit or loss.

Deferred tax is calculated at the tax rates that are enacted or substantively enacted by the end of the financial period and are expected to apply to the financial period when the asset is realised, or liability is settled. Deferred tax is credited in the consolidated statement of profit or loss and other comprehensive income except where it relates to items that may be credited directly to equity, in which case the deferred tax is adjusted directly against equity.

Deferred tax assets are recognised to the extent that it is probable that sufficient taxable amounts will be available against which deductible temporary tax differences or unused tax losses and tax offsets can be utilised.

Deferred tax assets and tax liabilities are offset when there is a legally enforceable right to offset current tax assets and tax liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the Group has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

The amount of benefits brought to account or which may be realised in the future is based on the assumption that no adverse change will occur in income taxation legislation and the anticipation that the Group will derive sufficient future assessable income to enable the benefit to be realised and comply with the conditions of deductibility imposed by law.

Tax Consolidation

The Company and its wholly owned Australian subsidiaries are part of an income tax-consolidated group under Australian taxation law. The Company is the head entity in the income tax-consolidated group. Tax income (expense), deferred tax liabilities and deferred tax assets arising from temporary tax differences of the members of the income tax-consolidated group are recognised in the separate financial statements of the members of the income tax-consolidated group using the 'stand-alone taxpayer' approach, by reference to the carrying amounts in the separate financial statements of each company and the tax values applying under tax consolidation. Current tax liabilities and tax assets and deferred tax assets arising from unused tax losses and tax credits of members of the income tax-consolidated group are recognised by the Parent Company (as head entity of the income tax-consolidated group).

Due to the existence of a tax funding agreement between the companies in the income tax-consolidated group, each company contributes to the income tax payable or receivable in proportion to their contribution to the income tax-consolidated group's taxable income. Differences between the amounts of net tax assets and tax liabilities derecognised and the net amounts recognised pursuant to the funding agreement are recognised as either a contribution by, or distribution to, the head entity.

Goods and Services Tax ('GST')

Revenues, expenses and assets are recognised net of the amount of GST, except where the amount of GST incurred is not recoverable from the Australian Taxation Office ('ATO'). In these circumstances, the GST is recognised as part of the cost of acquisition of the asset or equity or as part of an item of expense.

Receivables and payables in the consolidated statement of financial position are shown inclusive of GST.

The net amount of GST recoverable from, or payable to, the ATO, is included as current receivables or payables respectively in the consolidated statement of financial position.

Cash flows are included on a gross basis in the consolidated statement of cash flows. The GST components of cash flows arising from investing and financing activities, which are recoverable from, or payable to, the ATO, are classified as operating cash flows.

Commitments and contingencies are disclosed net of the amount of GST recoverable from, or payable to, the ATO.

Petroleum Resource Rent Tax ('PRRT')

PRRT is accounted for as income tax under AASB 112 *'Income Taxes'*.

(g) Cash and Cash Equivalents

Cash and cash equivalents in the consolidated statement of financial position and for presentation in the consolidated statement of cash flows comprise cash at bank and on hand (including share of joint operation cash balances) and short-term bank deposits that are readily convertible to known amounts of cash and are subject to insignificant risk of changes in value.

Note 1. Significant Accounting Policies Continued

(h) Receivables

Receivables, which normally have 30-45 day terms, are generally non-interest-bearing amounts. They are recognised initially at the amount of the consideration that is unconditional unless they contain significant financing components, when they are recognised initially at fair value. The Group holds receivables with the objective to collect the contractual cash flows. They are presented as current assets unless collection is not expected for more than 12 months after reporting date. For receivables expected to be settled within 12 months, these are subsequently measured at amortised cost using the effective interest method, less any loss allowance. For receivables expected to be settled later than 12 months, these are subsequently measured at amortised cost based on discounted cash flows using an effective interest rate, less any loss allowance.

Cash flows relating to non-current receivables are not discounted if the effect of discounting would be immaterial. Refer Note 3(c) for a description of the Group's receivable impairment policies.

(i) Inventories

Inventories are measured at the lower of cost and net realisable value. Net realisable value is the estimated selling price in the ordinary course of business, less the estimated costs of completion and selling expenses.

Cost for petroleum products, which comprise extracted crude oil stored in the FPSO, are valued using the absorption cost method.

Other inventories are represented by assets acquired from third parties, in the form of casing and other drilling inventory to be consumed or used in exploration and evaluation activities or production activities. They are presented as current assets unless inventories are not expected to be consumed or used in exploration and evaluation activities within 12 months. The cost of casing and other drilling inventory includes direct materials, direct labour and transportation costs.

(j) Security Deposits

Certain financial assets have been pledged as security for performance guarantees, bank guarantees and bonds related to exploration tenements and operating lease rental agreements. Their realisation may be restricted subject to terms and conditions attached to the relevant exploration tenement agreements or operating lease rental agreements.

Security deposits are non-derivative financial assets that are not quoted in an active market. Security deposits are initially recognised at fair value. Such assets are subsequently carried at amortised cost using the effective interest method, less any loss allowance. They are included in current assets, except for those with maturities greater than 12 months after the end of the reporting period which are classified as non-current assets.

Security deposits are derecognised when the terms and conditions attached to the relevant exploration tenement agreements or lease rental agreements have expired or been transferred.

Refer Note 3(c) for a description of the Group's security deposit impairment policies.

(k) Property, Plant and Equipment

Property, plant and equipment is stated at cost less accumulated depreciation and any accumulated impairment losses. Such cost includes the cost of replacing parts that are eligible for capitalisation when the cost of replacing the parts is incurred. Similarly, when each major inspection is performed, its cost is recognised in the carrying amount of the plant and equipment as a replacement only if it is eligible for capitalisation. All other repairs and maintenance are recognised as an expense in the consolidated statement of profit or loss and other comprehensive income as incurred.

Commencing from the time the plant and equipment is held ready for use, depreciation expense is calculated on a straight-line basis to allocate their cost amount, net of their residual values, over their estimated useful lives ranging from 2 to 10 years.

Plant and equipment residual values, useful lives and depreciation methods are reviewed, and adjusted if appropriate, at the end of each reporting period.

Gains and losses on disposals are determined by comparing proceeds with the net carrying amount. These gains and losses are included in the consolidated statement of profit or loss and other comprehensive income.

Property, plant and equipment are tested for impairment in accordance with the accounting policy described in Note 1(p).

(l) Oil and Gas Assets

Production assets

Production assets are stated at cost less accumulated amortisation and impairment charges. Production assets include the costs to acquire, construct, install or complete production and infrastructure facilities, capitalised borrowing costs, transferred exploration and evaluation assets, development wells and the estimated cost of dismantling and restoration. Subsequent capital costs, including major maintenance, are included in the asset's carrying amount only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be reliably measured.

Assets in development

When the technical and commercial feasibility of an undeveloped oil or gas field has been demonstrated and approval of commercial development occurs, the field enters its development phase. The costs of oil and gas assets in development are separately accounted for and include past exploration and evaluation costs, development drilling and other subsurface expenditure, surface plant and equipment and any associated land and buildings. When the committed development expenditure programs are completed and commercial production commences, these costs are subject to amortisation.

Amortisation of production assets

Amortisation is calculated using the units of production method for an asset or group of assets from the date of commencement of production. Depletion charges are calculated using the units of production method over the life of the estimated proved plus probable ('2P') reserves for an asset or group of assets.

(m) Intangibles

Computer Software

Computer software is stated at cost less accumulated amortisation and any accumulated impairment losses. Computer software costs have a finite life.

Commencing from the time the computer software is held ready for use, amortisation expense is calculated on a straight-line basis to allocate their cost amount, net of their residual values, over their estimated useful lives ranging from 2 to 2.5 years.

The assets' residual values, useful lives and amortisation methods are reviewed, and adjusted if appropriate, at the end of each reporting period. Computer software is tested for impairment in accordance with the accounting policy described in Note 1(p).

(n) 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 are capitalised as part of the cost of the asset. All other borrowing costs are expensed in the period in which they occur. Borrowing costs consist of interest and other costs that an entity incurs in connection with the borrowing of funds.

(o) Exploration and Evaluation Expenditure

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. Expenditure in respect of each area of interest is accounted for using the 'successful efforts' method of accounting. The 'successful efforts' method requires all exploration and evaluation expenditure in relation to an area of interest to be expensed in the period it is incurred, except the cost of successful wells, the costs of acquiring interests in new exploration assets, and appraisal costs relating to determining development feasibility, which are capitalised as intangible exploration and evaluation assets.

Exploration and evaluation assets are recognised in relation to an area of interest when the rights to tenure of the area of interest are current and either:

- it is expected to be recovered through sale or successful development and exploitation of the area of interest; or
- relates to an exploratory discovery for which at balance date a reasonable assessment of the existence or otherwise of economically recoverable reserves is not yet complete, or additional appraisal work is underway or planned.

All exploration expenditure in relation to directly attributable general administration costs, geological and geophysical costs, seismic and pre-tenure costs is expensed in the consolidated statement of profit or loss and other comprehensive income as incurred.

For exploration wells, costs directly associated with drilling the wells are initially capitalised on a well-by-well basis pending the evaluation of whether potentially economic reserves of hydrocarbons have been discovered. If no recoverable hydrocarbons are identified, or discoveries are deemed non-commercial, then the capitalised costs are expensed.

As capitalised exploration and evaluation expenditure is not available for use, it is not amortised.

Cash flows associated with exploration and evaluation expenditure expensed are classified as operating activities in the consolidated statement of cash flows. Whereas cash flows associated with capitalised exploration and evaluation expenditure are classified as investing activities.

When the technical feasibility and commercial viability of extracting economically recoverable reserves have been demonstrated, any related capitalised exploration and evaluation expenditure is reclassified as development expenditure in the consolidated statement of financial position. Prior to reclassification, capitalised exploration and evaluation expenditure is assessed for impairment.

Petroleum tenement acquisition costs capitalised, along with licence costs paid in connection with a right to explore in an existing exploration area.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 1. Significant Accounting Policies Continued

Farm-out

The Group does not record any exploration and evaluation expenditure made by a farmee, including any carries incurred by the farmee to earn an ownership interest.

Any cash consideration received on sale or farm-out of an area within an exploration area of interest is recognised as revenue in the consolidated statement of profit or loss and other comprehensive income, unless any of the consideration is attributable to capitalised exploration and evaluation expenditure. Cash consideration received in relation to capitalised exploration and evaluation expenditure is offset against the carrying value of the capitalised exploration and evaluation expenditure. Where the total carrying value has been recouped in this manner, the balance of the proceeds is brought to account as income as a gain on disposal.

Impairment of Capitalised Exploration and Evaluation Expenditure

The carrying value of capitalised exploration and evaluation expenditure is assessed for impairment at the asset level whenever facts and circumstances (as defined in AASB 6 *'Exploration for and Evaluation of Mineral Resources'*) suggest that the carrying amount of the asset may exceed its recoverable amount. If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated.

An impairment loss exists when the carrying amount of an asset or cash-generating unit exceeds its estimated recoverable amount. The asset or cash-generating unit is then written-down to its recoverable amount. Impairment losses are recognised as an expense in the consolidated statement of profit or loss and other comprehensive income.

(p) Impairment of Assets (Other than Capitalised Exploration and Evaluation Expenditure)

All other current and non-current assets (other than receivables, inventories, security deposits and deferred tax assets) are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

At the end of each reporting period, the Group conducts an internal review of asset values, which is used as a source of information to assess for any indicators of impairment. External factors, such as changes in economic conditions, are also monitored to assess for indicators of impairment. If any indication of impairment exists, an estimate of the asset's recoverable amount is calculated.

An impairment loss exists when the carrying amount of an asset or cash-generating unit exceeds its estimated recoverable amount. The asset is then written down to its recoverable amount. Recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows that are largely independent of the cash inflows from other assets or groups of assets (cash-generating units).

Impairment losses are recognised as an expense in the consolidated statement of profit or loss and other comprehensive income.

Assets that suffered impairment are tested for possible reversal of the impairment loss whenever events or changes in circumstances indicate that the impairment may have reversed.

(q) Trade and Other Payables

Trade and other payables are initially recognised at their fair value and subsequently measured at amortised cost using the effective interest method. These amounts represent liabilities for goods and services provided to the Group prior to the end of the reporting period that are unpaid and arise when the Group becomes obliged to make future payments in respect of the purchase of goods and services. The amounts are unsecured and are usually paid within 30 days of recognition. They are presented as current liabilities unless payment is not due within twelve months from the reporting date.

(r) 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. A derivative embedded in a hybrid contract, with a financial liability or non-financial host, is separated from the host and accounted for as a separate derivative if the economic characteristics and risks are not closely related to the host, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the hybrid contract is not measured at fair value through profit or loss. Embedded derivatives are measured at fair value with changes in fair value recognised in profit or loss. 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.

For purposes of subsequent measurement, financial liabilities are classified in two categories: financial liabilities at fair value through profit or loss and financial liabilities at amortised cost (loans and borrowings).

The Group's financial liabilities include trade and other payables, borrowings, derivative financial instruments designated as cash flow hedges, and a derivative financial instrument relating to contingent consideration for the acquisition of an asset.

Derivatives designated as hedging instruments

The Group has entered into derivative financial instruments to hedge its exposure to cash flow risk from movements in oil price (commodity price risk) arising from highly probable forecasted future oil sales.

At the inception of a hedge relationship, the Group documents the risk management objective and strategy for undertaking the hedge transaction. The documentation includes identification of the hedging instrument, the hedged item, the nature of the risk being hedged and how the Group will assess whether the hedging relationship meets the hedge effectiveness requirements (including the analysis of sources of hedge ineffectiveness and how the hedge ratio is determined). A hedging relationship qualifies for hedge accounting if it meets all of the following effectiveness requirements:

- there is 'an economic relationship' between the hedged item and the hedging instrument.
- The effect of credit risk does not 'dominate the value changes' that result from that economic relationship.
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Group actually hedges and the quantity of the hedging instrument that the Group actually uses to hedge that quantity of hedged item.

Derivative financial instruments are presented as current assets or liabilities to the extent they are expected to be realised or settled within twelve months after the end of the reporting period. Hedges that meet all the qualifying criteria for hedge accounting are accounted for as described below.

Cash flow hedges

When a derivative is designated as a cash flow hedging instrument, the effective portion of changes in the fair value of the derivative is recognised in other comprehensive income ('OCI') and accumulated in the hedging reserve. The effective portion of changes in the fair value of the derivative that is recognised in OCI is limited to the cumulative change in fair value of the hedged item, determined on a present value basis, from inception of the hedge. Any ineffective portion of changes in the fair value of the derivative is recognised immediately in profit or loss. The Group designates only the change in fair value of the spot element of the derivative transaction contracts (the intrinsic value of the option) as the hedging instrument in cash flow hedging relationships. The change in fair value of the value of the option contract in time is separately accounted for as a cost of hedging and recognised in a costs of hedging reserve within equity.

For all financial hedged derivative transaction contracts, the amount accumulated in the hedging reserve and the cost of hedging reserve is reclassified to profit or loss in the same period or periods during which the hedged expected future cash flows affect profit or loss. If the hedge no longer meets the criteria for hedge accounting or the hedging instrument is sold, expires, is terminated or is exercised, then hedge accounting is discontinued prospectively. When hedge accounting for cash flows is discontinued, the amount that has been accumulated in the hedging reserve remains in equity until it is reclassified to profit or loss in the same period or periods as the hedged expected future cash flows affect profit or loss. If the hedged future cash flows are no longer expected to occur, then the amounts that have been accumulated in the hedging reserve and the cost of hedging reserve are immediately reclassified to profit or loss. Further details are disclosed in Note 23.

(s) Employee Benefits

Wages, Salaries, Annual Leave and Personal Leave

Liabilities for wages and salaries, including non-monetary benefits and annual leave expected to be settled within 12 months after the end of the reporting period in which the employees render the related services are recognised in respect of employees' services up to the end of the reporting period. They are measured at the amounts expected to be paid when the liabilities are settled plus related on-costs. Expenses for non-vesting personal leave are recognised when the leave is taken and are measured at the rates paid or payable.

The obligations are presented as current liabilities in the consolidated statement of financial position if the Group does not have an unconditional right to defer settlement for at least twelve months after the reporting date, regardless of when the actual settlement is expected to occur.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 1. Significant Accounting Policies Continued

Share-based Payments

Share-based remuneration benefits are provided to Executive Directors and employees via the Company's PRP and ESOP (refer Note 31). The Group issues equity-settled and cash-settled share-based payments to certain employees.

The fair value of share options and performance rights granted is recognised as a share-based payments expense in the consolidated statement of profit or loss and other comprehensive income. The total amount to be expensed is determined by reference to the fair value of the share options and performance rights granted, which includes any market performance conditions, but excludes the impact of any service and non-market performance vesting conditions. Non-market performance vesting conditions are included in assumptions about the number of share options or performance rights that are expected to vest.

The fair value is measured at grant date. For equity-settled share-based payments the corresponding credit is recognised directly in the share-based payments reserve in equity. For cash-settled share-based payments a liability is recognised based on fair value of the payable earned by the end of the reporting period. The liability is re-measured to fair value at each reporting date up to, and including the vesting date, with changes in fair value recognised in share-based payments expense. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied. At the end of each reporting period, the Group revises its estimates of the number of share options and performance rights that are expected to vest based on the non-market performance vesting conditions. It recognises the impact of the revision to original estimates, if any, in the consolidated statement of profit or loss and other comprehensive income.

The fair value of share options at grant date is determined using a Black-Scholes option pricing model that takes into account the exercise price, the term of the share option, the impact of dilution, the non-tradeable nature of the share option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the share option.

The fair value of performance rights, granted for $Nil consideration, at grant date is based on the Company's closing share price at that date, with the exception of long-term performance rights granted during the current financial year.

Long term performance rights granted during the current financial year, which are subject to market-based performance conditions, have been valued using a Monte Carlo simulation approach.

(t) Provisions

Provisions are recognised when the Group has a present obligation (legal or constructive) 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.

Restoration costs

A provision for restoration is provided by the Group where there is a present obligation as a result of exploration, development or production activities having been undertaken, and it is probable that an outflow of economic benefits will be required to settle the obligation. The estimated future obligations include the estimated costs of decommissioning and removing an asset and restoring the site. These costs are capitalised within the cost of the associated assets and the provision is stated in the statement of financial position at total estimated present value and amortised on the same basis as the associated asset. These costs are based on judgements and assumptions regarding removal dates, technologies, industry practice and relevant legislation. Over time, the liability is increased for the change in the present value based on a risk adjusted pre-tax discount rate appropriate to the risks inherent in the liability. The costs of restoration are brought to account in the statement of comprehensive income through depletion of the associated assets over the economic life of the projects with which these costs are associated. The unwinding of the discount is included as an accretion charge within finance costs.

Long Service Leave

A provision has been recognised for employee entitlements relating to long service leave measured at the discounted value of estimated future cash outflows. In determining the provision, consideration is given to employee wage increases and the probability that the employee may satisfy vesting requirements. The cash outflows are discounted using market yields with terms of maturity that match the expect timing of cash outflows.

Employee entitlements relating to long service leave are presented as a current provision in the consolidated statement of financial position if the Group does not have an unconditional right to defer settlement for at least twelve months after the reporting period, regardless of when the actual settlement is expected to occur.

(u) Contributed Equity

Ordinary shares are classified as equity.

Transaction costs directly attributable to the issue of new ordinary shares, share options or performance rights are shown in equity as a deduction, net of any related income tax, from the proceeds. Transaction costs are the costs that are incurred directly in connection with the issue of new ordinary shares, and which would not have been incurred had those ordinary shares not been issued. These directly attributable transaction costs include registration and other regulatory fees, amounts paid to legal, accounting and other professional advisers, printing costs and marketing costs.

Where the Company acquires its own ordinary shares, as a result of a share buy-back, those ordinary shares are cancelled. No gain or loss is recognised, and the consideration paid to acquire the ordinary shares, including any transaction costs directly attributable, net of any related income tax, is recognised directly as a reduction from equity.

(v) Interests in Joint Operations

A joint operation is a joint arrangement whereby the participants that have joint control of the arrangement (i.e. joint operators) have rights to the assets, and obligations for the liabilities, relating to the arrangement.

The Group recognises assets, liabilities, revenues and expenses according to its share in the assets, liabilities, revenues and expenses of a joint operation or similar as determined and specified in contractual arrangements (joint operating agreements). These have been incorporated in the consolidated financial statements under the appropriate headings.

The Group's share of assets, liabilities, revenues and expenses employed in joint operations is set out in Note 27.

(w) Leases

The Group has lease contracts for property, an FPSO vessel and other equipment used in its operations. The Group recognises a right-of-use asset and a lease liability at the lease commencement date.

The lease liability is initially measured at the present value of the lease payments expected to be paid over the lease term, discounted using the interest rate implicit in the lease or, if the rate cannot be readily determined, the Group's estimated incremental borrowing rate. The lease liability is subsequently increased by the interest cost on the lease liability and decreased by lease payments made. The lease liability is further remeasured if the estimated future lease payments change as a result of index or rate changes, residual value guarantees or likelihood of exercise of purchase, extension or termination options.

The Group has applied judgement to determine the lease term for lease contracts that include renewal options. The assessment of whether the Group is reasonably certain to exercise such options impacts the lease term, which affects the measurement of lease liabilities and right-of-use assets recognised.

Right-of-use assets

The right-of-use asset is initially measured at cost (present value of the lease liability plus deemed cost of acquiring the asset), and subsequently at cost less any accumulated depreciation, impairment losses and adjustment for remeasurement of the lease liability.

Property leases generally have terms between 2 and 5 years. The FPSO vessel lease has a fixed term to February 2026 with renewal options available.

(x) Earnings Per Share

Basic Earnings Per Share

Basic earnings per ordinary share is calculated by dividing the profit or loss attributable to owners of the Company, excluding any costs of servicing equity other than ordinary shares, by the weighted average number of ordinary shares outstanding during the financial year, adjusted for any bonus elements in ordinary shares issued during the financial year.

Diluted Earnings Per Share

Diluted earnings per ordinary share adjusts the figures used in the determination of basic earnings per ordinary share to take into account the after-income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of ordinary shares that would have been outstanding assuming the conversion of all dilutive potential ordinary shares.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 1. Significant Accounting Policies Continued

(y) Parent Company Financial Information

The financial information for the Parent Company, Karoon Energy Ltd, disclosed in Note 33 has been prepared on the same basis as the consolidated financial statements, except as set out below:

Investments in Subsidiaries

Investments in subsidiaries are accounted for at cost in the Parent Company's financial statements.

The Parent Company does not designate any investments in subsidiaries as being subject to the requirements of Australian Accounting Standards specifically applicable to financial instruments. They are held for strategic and not trading purposes.

Investments in subsidiaries and receivables from subsidiaries are tested for impairment in accordance with the accounting policy described in Note 1(p).

Share-based Payments

The grant by the Company of equity-settled share options and performance rights over its ordinary shares to the employees of subsidiary companies in the Group is treated as a capital contribution to that subsidiary company. The fair value of employee services received, measured by reference to the grant date fair value, is recognised over the vesting period as an increase to investments in subsidiaries, with a corresponding credit to equity.

(z) New Australian Accounting Standards and Interpretations for Application in Future Financial Years

There are no relevant new Australian Accounting Standards or Interpretations that are not yet effective and that are expected to have a material impact on the Group in the current or future financial years and on foreseeable future transactions.

(aa) Comparative figures

When required by Accounting Standards, comparative figures have been adjusted to conform to changes in presentation for the current period.

Note 2. Significant Accounting Estimates, Assumptions and Judgements

Revenues and expenses and the carrying amounts of certain assets and liabilities are often determined based on estimates and assumptions of future events. In applying the Group's significant accounting policies, the Board of Directors and management evaluate estimates and judgements based on historical knowledge and best available current information. Estimates assume a reasonable expectation of future events and are based on current trends and economic data obtained both externally and within the Group.

Significant estimates, assumptions and/or judgements made by the Board of Directors and management in the preparation of the consolidated financial statements were:

(a) Impairment of oil and gas assets

The Group assesses whether oil and gas assets are impaired at least on a semi-annual basis. This requires review of the indicators of impairment and/or an estimation of the recoverable amount of the cash-generating unit to which the assets belong. For oil and gas properties, expected future cash flow estimation is based on reserves, future production profiles, commodity prices and costs. Current climate change legislation is also considered in relation to oil price forecasts and the cash generating unit's useful life. Future uncertainty around climate change risks continue to be monitored.

(b) Capitalised Exploration and Evaluation Expenditure

Capitalised exploration and evaluation expenditure is carried forward on the basis that exploration and evaluation operations in the areas of interest have not at the end of the reporting period reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and active and significant operations in, or in relation to, the areas of interest are continuing.

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the related exploration tenement itself or, if not, whether it successfully recovers the related exploration and evaluation asset through sale. Factors that could affect the future recoverability include the level of economically recoverable reserves, future technological changes which could impact the cost of development, future legal changes (including changes to environmental and restoration obligations) and changes to commodity prices. To the extent that capitalised exploration and evaluation expenditure is determined not to be recoverable in the future, the relevant capitalised amount will be impaired in the consolidated statement of profit or loss and other comprehensive income and net assets will be reduced during the financial period in which this determination is made.

Information on the reasonable existence or otherwise of economically recoverable reserves is progressively gained through geological analysis and interpretation, drilling activity and prospect evaluation during a normal exploration tenement term. A reasonable assessment of the existence or otherwise of economically recoverable reserves can generally only be made, therefore, at the conclusion of those exploration and evaluation activities.

(c) Provision for Restoration

Restoration costs are a normal consequence of operating in the oil and gas industry. A provision has been recognised for the Group's restoration obligations for the Baúna field.

In determining an appropriate level of provision, consideration is given to the expected future costs to be incurred, the timing of these expected future costs, the estimated future level of inflation and appropriate discount rate. The ultimate costs of restoration are uncertain and cost estimates could be subject to revisions in subsequent years due to many factors including changes to the relevant legal and legislative requirements, the emergence of new restoration techniques or experience at other fields. Risks associated with climate change also continue to be monitored. Likewise, the appropriate future discount rates used in the calculation are subject to change according to the risks inherent in the liability. The discount rate used to determine the restoration obligation at 30 June 2022 was based on applicable government bond rates with a tenure aligned to the tenure of the liability.

Changes to any of the estimates could result in a significant change to the level of provisioning required, which would in turn impact future financial results.

(d) Estimates of reserves quantities

The estimated quantities of Proved plus Probable ("2P") hydrocarbon reserves reported by the Group are integral to the calculation of depletion and depreciation expense and to the assessment of impairment or impairment reversals.

Estimated reserves quantities are based upon management's interpretations of geological and geophysical models, reservoir engineering and production engineering analyses and models, and assessments of the technical feasibility and commercial viability of producing the reserves, taking into consideration reviews by an independent third party. An external reserves assessment is planned to be undertaken at least every 3 years.

Assessments require assumptions to be made regarding future development and production costs, commodity prices, exchange rates and fiscal regimes. The Group prepares its reserves estimates in accordance with the Petroleum Resources Management System (PRMS 2018) published by the Society of Petroleum Engineers and the Australian Securities Exchange Listing rules. All estimates of reserves reported by the Group are prepared by, or under the supervision of a qualified petroleum reserves and resources evaluator.

Estimates of reserves may change from period to period as the economic assumptions used to estimate the reserves can change from period to period, and as additional geological data is generated during the course of operations. These changes may impact depreciation, amortisation, asset carrying values, restoration provisions and deferred tax balances. If proved and probable reserves estimates are revised downwards, earnings could be affected by a higher depreciation and/or amortisation charge or immediate write-down of the assets carrying value.

(e) Fair value measurement of financial instruments

When the fair values of financial assets and financial liabilities recorded in the statement of financial position cannot be measured based on quoted prices in active markets, their fair value is measured using valuation techniques including the discounted cash flow model. The fair value of the contingent consideration (refer to Note 23) is based on the Group's internal assessment of future oil prices, which considers industry consensus and observable prices, inflation and an appropriate risk-free rate. Changes in assumptions relating to these factors could affect the reported fair value of the financial instrument.

(f) Share-based Payments

Estimating fair value for share-based payment transactions requires determination of the most appropriate valuation model, which depends on the terms and conditions of the grant. This estimate also requires determination of the most appropriate inputs to the valuation model including the expected life of the share option or performance right, volatility and dividend yield and making assumptions about them at grant date. The fair value of share options is ascertained using the Black-Scholes option pricing model taking into account the terms and conditions upon which the share options were granted. The fair value of long-term performance rights issued during the current financial year are valued using a Monte Carlo simulation approach taking into account the terms and conditions upon which the performance rights were granted. The cumulative share-based payments expense recognised reflects the extent, in the opinion of management, to which the vesting period has expired and the number of share options and performance rights granted that will ultimately vest or be settled in cash. At the end of each reporting period, the unvested share options, performance rights and cash-settled share-based payment liability are adjusted by the number forfeited during the reporting period to reflect the actual number of share options and performance rights outstanding and cash liability to be settled. In addition, the fair value of cash-settled share-based payments are remeasured, up to the date of settlement, to reflect the cash liability at the end of each reporting period with changes in the fair value recognised in the profit or loss.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 2. Significant Accounting Estimates, Assumptions and Judgements Continued

(g) Income Tax

The Group is subject to income taxes in Australia, Brazil and other jurisdictions where it has foreign operations. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Group estimates its tax liabilities based on the Group's understanding of the relevant tax laws. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax balances in the financial period in which such determination is made.

Assessing the future utilisation of tax losses and temporary tax differences requires the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws. To the extent that future utilisation of these tax losses and temporary tax differences becomes probable, this could result in significant changes to deferred tax assets recognised, which would in turn impact future financial results.

(h) Joint Arrangements

Exploration and evaluation activities of the Group are conducted primarily through arrangements with other participants. Each arrangement has a contractual agreement (joint operating agreement) that provides the participants with rights to the assets and obligations for the liabilities of the arrangement. Under certain agreements, more than one combination of participants can make decisions about the relevant activities and therefore joint control does not exist. Where the arrangement has the same legal form as a joint operation, but is not subject to joint control, the Group accounts for its interest in accordance with the contractual agreement by recognising its share of jointly held assets, liabilities, revenues and expenses of the arrangement.

(i) Determining the lease term of contracts with renewal options

The Group determines the lease term as the non-cancellable term of the lease, together with any periods covered by an option to extend the lease if it is reasonably certain to be exercised, or any periods covered by an option to terminate the lease, if it is reasonably certain not to be exercised.

The Group has several lease contracts that include renewal options. The Group applies judgement in evaluating whether it is reasonably certain whether or not to exercise the option to renew the lease. That is, it considers all relevant factors that create an economic incentive for it to exercise the renewal. After the commencement date, the Group reassesses the lease term if there is a significant event or change in circumstances that is within its control and affects its ability to exercise or not to exercise the option to renew or to terminate. The Group included the renewal periods as part of the lease term for the FPSO right-of-use asset as there will be a significant negative effect on production if a replacement asset is not readily available.

Note 3. Financial Risk Management

The Group's activities expose it to a variety of financial risks: market risk (including foreign exchange risk and interest rate risk); commodity price risk; credit risk; and liquidity risk. The Group's overall financial risk management program focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the financial performance of the Group. The Group uses different methods to measure the different types of financial risk to which it is exposed. These methods include sensitivity analysis in the case of foreign exchange, interest rates and commodity prices.

The overall financial risk management strategy of the Group is governed by the Board of Directors through the Audit and Risk Committee and is primarily focused on ensuring that the Group is able to finance its business plans, while minimising potential adverse effects on financial performance. The Board of Directors provides written principles for overall financial risk management, as well as written policies covering specific areas, such as mitigating foreign exchange, interest rate, commodity price and credit risks, use of derivative financial instruments and investment of excess cash. Financial risk management is carried out by the Company's finance function under policies approved by the Board of Directors. The finance function identifies, evaluates and if necessary, hedges financial risks in close co-operation with the Chief Executive Officer and Managing Director. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and Group activities.

Details of the significant accounting policies and methods adopted, including the criteria for recognition, the basis of measurement and the basis on which income and expenses are recognised in respect of each class of financial asset and financial liability are disclosed in Note 1.

The Group's financial instruments consist of cash and cash equivalents, receivables, security deposits, trade and other payables, lease liabilities, borrowings, derivative financial instruments designated as cash flow hedges, and embedded derivatives.

The totals for each category of financial instruments in the consolidated statement of financial position are as follows:

	NOTE	CONSOLIDATED 2022 US$'000	2021 US$'000
Financial assets			
Cash and cash equivalents	10	**157,683**	133,209
Receivables	11	**56,336**	34,162
Security deposits	13	**1,662**	1,615
Total financial assets		**215,681**	168,986
Financial liabilities			
Trade and other payables (refer note (i) below)		**73,614**	79,066
Borrowings (refer note (ii) below)	22	**30,000**	–
Other financial liabilities (refer note (iii) below)	23	**347,392**	71,161
Lease liabilities	21	**288,887**	312,840
Total financial liabilities		**739,893**	463,067

(i) Trade and other payables above exclude amounts relating to annual leave liabilities, which are not considered a financial instrument.

(ii) Borrowings exclude transaction costs which are not considered a financial instrument.

(iii) Other financial liabilities relate to the contingent consideration payable to Petrobras as part of the acquisition of Baúna and derivative financial liabilities designated as cash flow hedges (refer Note 23).

(a) Market Risk

(i) Foreign Exchange Risk

Foreign exchange risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. Foreign exchange risk arises when future commercial transactions and recognised financial assets and financial liabilities are denominated in a currency that is not the Company's functional currency.

The Group's revenue, significant operating expenditure including the FPSO charter lease and a large component of capital obligations are predominantly denominated in US$.

The Group's remaining foreign exchange risk exposures relate to administrative and business development expenditures incurred at the corporate level in A$; and operating and capital expenditures incurred by the Group in relation to operating the Baúna production asset in Brazil in Brazilian REAL. These items are restated to US$ equivalents at each period end, and the associated gain or loss is taken to the Statement of Profit and Loss and Other Comprehensive Income.

The Group manages foreign exchange risk at the corporate level by monitoring forecast cash flows in currencies other than US$ and ensuring that adequate Brazilian REAL and A$ cash balances are maintained.

Foreign currencies are bought on the spot market in excess of immediate requirements. Where currencies are purchased in advance of requirements, these balances do not usually exceed 3 months' requirements. The appropriateness of A$ and Brazilian REAL holdings are reviewed regularly against future commitments and current $A and Brazil REAL market expectations.

Periodically, sensitivity analysis is conducted to evaluate the potential impact of unfavourable exchange rates on the Group's future financial position. The results of this evaluation are used to determine the most appropriate risk mitigation tool to be used. The Group will hedge when it is deemed the most appropriate risk mitigation tool to be used. Foreign currency hedging transactions were not entered into during the financial year or previous financial year.

The Group is not exposed to material translation exposures at the end of the current financial year as the majority of its financial assets and liabilities are denominated in US$ and as such, no foreign currency sensitivity analysis has been disclosed.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 3. Financial Risk Management Continued

(ii) Interest Rate Risk

Interest rate risk is the risk that the fair value of future cash flows of financial assets and financial liabilities will fluctuate because of changes in market interest rates. Interest rate risk is managed on a Group basis at the corporate level. This risk is managed through the use of cash flow forecasts supplemented by sensitivity analysis.

As at 30 June 2022 and 30 June 2021, there was no interest rate hedging in place.

The Group's interest rate risk arises from long-term borrowings at floating rates and cash and cash equivalent and security deposits which earn interest at floating rates. As long-term borrowings and the majority of cash and cash equivalents are held in US$'s, the primary exposure is to US$ interest rates.

An analysis of the Group's exposure to interest rate risk for financial assets and financial liabilities at the end of the financial year is set out below:

	CONSOLIDATED					
2022	**WEIGHTED AVERAGE INTEREST RATE % P.A.**	**FLOATING INTEREST RATE US$'000**	**FIXED INTEREST RATE US$'000**	**NON-INTEREST BEARING US$'000**	**FAIR VALUE US$'000**	**CARRYING AMOUNT US$'000**
Financial assets						
Cash and cash equivalents	**0.00**	**47,028**	**–**	**110,655**	**157,683**	**157,683**
Receivables	**–**	**–**	**–**	**56,336**	**56,336**	**56,336**
Security deposits	**7.09**	**1,496**	**155**	**11**	**1,662**	**1,662**
Total financial assets		**48,524**	**155**	**167,002**	**215,681**	**215,681**
Financial liabilities						
Trade and other payables	**–**	**–**	**–**	**73,614**	**73,614**	**73,614**
Borrowings	**5.95**	**30,000**	**–**	**–**	**30,000**	**30,000**
Other financial liabilities	**2.00**	**–**	**298,280**	**49,112**	**347,392**	**347,392**
Lease liabilities	**–**	**–**	**–**	**288,887**	**288,887**	**288,887**
Total financial liabilities		**30,000**	**298,280**	**411,613**	**739,893**	**739,893**

	CONSOLIDATED					
2021	**WEIGHTED AVERAGE INTEREST RATE % P.A.**	**FLOATING INTEREST RATE US$'000**	**FIXED INTEREST RATE US$'000**	**NON-INTEREST BEARING US$'000**	**FAIR VALUE US$'000**	**CARRYING AMOUNT US$'000**
Financial assets						
Cash and cash equivalents	0.11	71,487	–	61,722	133,209	133,209
Receivables	–	–	–	34,162	34,162	34,162
Security deposits	3.27	1,372	169	73	1,615	1,615
Total financial assets		72,859	169	95,957	168,986	168,986
Financial liabilities						
Trade and other payables	3.10	42,422	–	36,643	79,066	79,066
Other financial liabilities	2.00	–	71,161	–	71,161	71,161
Lease liabilities	–	–	–	312,840	312,840	312,840
Total financial liabilities		42,422	71,161	349,483	463,067	463,067

Interest Rate Sensitivity Analysis

The following table details the Group's sensitivity to a 1% p.a. increase or decrease in interest rates, with all other variables held constant. The sensitivity analysis is based on the balance of floating interest rate amounts held at the end of the financial year.

The sensitivity analysis is not fully representative of the inherent interest rate risk, as the financial year end exposure does not necessarily reflect the exposure during the course of a financial year. These sensitivities should not be used to forecast the future effect of movements in interest rates on future cash flows.

	CONSOLIDATED 2022 US$'000	2021 US$'000
Change in profit (loss) before income tax		
– Increase of interest rate by 1% p.a.	**365**	304
– Decrease of interest rate by 1% p.a.	**(95)**	(43)
Change in financial instruments		
– Increase of interest rate by 1% p.a.	**365**	304
– Decrease of interest rate by 1% p.a.	**(95)**	(43)

(b) Commodity Price Risk

The Group is exposed to commodity price fluctuations associated with the production and sale of oil. Commodity price risk is managed on a Group basis at the corporate level. To mitigate commodity price risk, during the period, the Group entered into Brent oil price cash flow hedges, via a collar structure consisting of bought put and sold call options covering the period from December 2021 to March 2024. From December 2021 until June 2022, approximately 39% of actual production volume was hedged. At reporting date, the Group held hedging financial instruments with a net liability carrying value of $49.1m (refer Note 23)

Commodity Price Sensitivity Analysis – Cash Flow Hedges

The following table details the Group's sensitivity to a 10% increase or decrease in the Brent oil price, with all other variables held constant.

	CONSOLIDATED 2022 US$'000	2021 US$'000
Change in cash flow hedge reserves (in accordance with hedge accounting application)		
– Increase of oil price by 10%	**(47,814)**	–
– Decrease of oil price by 10%	**47,814**	–
Change in financial liabilities		
– Increase of oil price by 10%	**(47,814)**	–
– Decrease of oil price by 10%	**47,814**	–

Commodity Price Sensitivity Analysis – Contingent Consideration

As part of the acquisition of Baúna, the Group agreed to pay Petrobras contingent consideration of up to $285 million plus interest of 2% per annum accruing from 1 January 2019. The fair value of the contingent consideration has been accounted for as an embedded derivative and estimated calculating the present value of the future expected cash out flows. The estimates are based on the Group's internal assessment of future oil prices. A discount rate of 2.38% and 2% inflation factor has also been applied. Refer to Note 23 for more details.

The following table details the Group's sensitivity to a 10% increase or decrease in its internal assessment of future oil prices on the contingent consideration payable to Petrobras. At 30 June 2022, with the US$70 per barrel threshold triggered over calendar years 2022-2026, the maximum contingent consideration payable has been recognised and as such a 10% increase in the oil price would have no impact on the financial statements.

	CONSOLIDATED 2022 US$'000	2021 US$'000
Change in profit (loss) before income tax		
– Increase of oil price by 10%	**–**	(77,791)
– Decrease of oil price by 10%	**43,081**	54,696
Change in financial liabilities		
– Increase of oil price by 10%	**–**	77,791
– Decrease of oil price by 10%	**(43,081)**	(54,696)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 3. Financial Risk Management Continued

(c) Credit Risk

The maximum exposure to credit risk at the end of the financial year is the carrying amount of the financial assets as disclosed in the consolidated statement of financial position and notes to the consolidated financial statements.

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. Credit risk arises from cash and cash equivalents and security deposits held with banks, financial institutions and joint operators, as well as credit exposures to customers, including outstanding receivables and refundable tax credits.

Credit risk is managed on a Group basis at the corporate level. To minimise credit risk, the Group has adopted a policy of only dealing with recognised and creditworthy third parties. Receivable balances are monitored on an ongoing basis with the result being the Group's exposure to bad debts is minimised. The Group does not currently hold collateral, nor does it securitise its receivables.

The Group has policies in place to ensure that services are made to customers with an appropriate credit history.

Cash and cash equivalents and security deposit counterparties are limited to credit quality banks and financial institutions. For banks and financial institutions in Australia, only independently rated counterparties with a minimum rating of Aa3/A2 are accepted. For banks and financial institutions in Brazil, only independently rated counterparties with a minimum rating of Baa1 are accepted. For banks and financial institutions in Brazil, with independently rated counterparty ratings below Baa1, exposure cannot exceed the short-term country specific cash requirements unless they are associated banks of an International Bank with a higher credit rating. Cash and cash equivalents are held offshore by the Group's Brazilian subsidiary out of London with an International Bank with a rating of Aa3. The Group's credit exposure and external credit ratings of its counterparties are monitored on a periodic basis. Where commercially practical, the Group seeks to limit the amount of credit exposure to any one bank or financial institution.

(i) Impairment of Financial Assets

The Group has 2 types of financial assets that are subject to AASB 9's 'expected credit loss' model: receivables and security deposits. The Group has applied the AASB 9 general model approach to measuring expected credit losses for all receivables and security deposits.

While cash and cash equivalents are also subject to the impairment requirements of AASB 9, the identified impairment loss was considered not significant given the counterparties and/or the short maturity.

Expected Credit Loss

When required, the carrying amount of the relevant financial asset is reduced through the use of a loss allowance account and the amount of any loss is recognised in the statement of profit or loss and other comprehensive income. When measuring expected credit losses, balances are reviewed based on available external credit ratings, historical loss rates and the days past due.

Security Deposits

The Group's security deposits held in Australia are considered to have low credit risk on the basis that there is a low risk of default with the relevant bank counterparty. Management considers 'low credit risk' for security deposits with banks and financial institutions to be an investment grade credit rating with at least 1 major rating agency.

The Group is exposed to credit risk in relation to a security deposit of $1,182k (30 June 2021: $1,237k) held with Itau Unibanco SA in Brazil. The Group provided the ANP (the Brazilian oil and gas regulator) a letter of credit to carry out the minimum work program in relation to exploration in Santos Basin Block S-M-1537. The letter of credit is fully funded by way of payment of a security deposit (refer Note 13(b)), which will be released once the work program is met. The credit rating of Itau Unibanco SA is Ba2 (30 June 2021: Ba2), which is a non-investment grade rating that carries substantial credit risk. The credit rating of Itau Unibanco SA in Brazil is monitored on a periodic basis for credit deterioration. In addition, Management continually monitors Brazilian macro-economic factors for any deterioration which directly impacts the credit ratings of Brazilian financial institutions. As there has not been a significant increase in credit risk since initial recognition of this security deposit, which is predominantly impacted by negative macro-economic factors in Brazil, any impairment test uses a 12-month expected credit loss model measure.

As at 30 June 2022, there were $Nil (30 June 2021: $Nil) security deposits past due. The loss allowance recognised during the financial year for security deposits was $Nil. Accordingly, interest income revenue has been calculated on the gross carrying amount during the financial year (30 June 2021: $Nil).

Receivables

The Group's receivables relating to Brazil and Australia are considered to have low credit risk on the basis that there is a low risk of default and the debtor has a strong (robust) capacity to meet its obligations in the short-term. Accordingly, for receivables any impairment test uses a 12-month expected credit loss model measure.

The Group is exposed to credit risk in relation to an interest receivable of $318k (30 June 2021: $121k) predominantly related to the security deposit held with Itau Unibanco SA in Brazil. As there has not been a significant increase in credit risk since initial recognition of the security deposit, which is predominantly impacted by negative macro-economic factors in Brazil, any impairment test uses a 12-month expected credit loss model measure.

As at 30 June 2022, there were $Nil (30 June 2021: $Nil) receivables past due. The loss allowance for receivables recognised during the financial year was considered to be $Nil (30 June 2021: $Nil).

(d) Liquidity Risk

Liquidity risk is the risk that the Group will encounter difficulty in meeting obligations associated with financial liabilities.

The Group manages liquidity risk by ensuring that there are sufficient funds available to meet financial obligations on a day-to-day basis and to meet unexpected liquidity needs in the normal course of business. Emphasis is placed on ensuring there is sufficient funding in place to meet the ongoing operational requirements of the Group's production activities, exploration, evaluation and development expenditure, and other corporate initiatives.

The following mechanisms are utilised to manage liquidity risk:

- preparing and maintaining rolling forecast cash flows in relation to operational, investing and financing activities;
- comparing the maturity profile of financial liabilities with the realisation profile of financial assets;
- managing credit risk related to financial assets;
- when necessary, utilising short-term and long-term loan facilities;
- investing surplus cash only in credit quality banks and financial institutions; and
- maintaining a reputable credit profile.

At the end of the financial year, the Group held cash and cash equivalents at call of $157,683k (30 June 2021: $133,209k) that are expected to readily generate cash inflows for managing liquidity risk. The Group had external borrowings of $30,000k (30 June 2021: $Nil).

The Group had access to the following undrawn borrowing facilities at the end of the reporting period:

	2022 US$'000	2021 US$'000
Floating rate		
– Expiring beyond one year (syndicated loan facility and accordion facility)	**180,000**	–

An analysis of the Group's financial liabilities contractual maturities at the end of the financial year is set out in the tables below. The amounts disclosed in the table are the contractual undiscounted cash flows comprising principal and interest repayments.

	CONSOLIDATED					
	LESS THAN 6 MONTHS US$'000	6-12 MONTHS US$'000	1-3 YEARS US$'000	3-5 YEARS US$'000	OVER 5 YEARS US$'000	TOTAL US$'000
2022						
Financial liabilities						
Non-derivative financial liabilities						
Trade and other payables	**69,295**	**3,306**	**7,985**	**–**	**–**	**80,586**
Borrowings	**–**	**–**	**30,000**	**–**	**–**	**30,000**
Lease liabilities	**29,774**	**29,396**	**119,044**	**118,395**	**43,113**	**339,722**
Derivative financial liabilities						
Derivative financial instruments – cash flow hedges	**20,585**	**20,182**	**8,345**	**–**	**–**	**49,112**
Contingent consideration – embedded derivative	**–**	**84,631**	**174,422**	**59,103**	**–**	**318,156**
Total financial liabilities	**119,654**	**137,515**	**339,796**	**177,498**	**43,113**	**817,576**
2021						
Financial liabilities						
Non-derivative financial liabilities						
Trade and other payables	32,382	42,422	4,262	–	–	79,066
Lease liabilities	32,596	29,513	110,269	109,518	94,563	376,459
Derivative financial liabilities						
Contingent consideration – embedded derivative	–	–	37,263	28,414	7,052	72,729
Total financial liabilities	64,978	71,935	151,794	137,932	101,615	528,254

Note 3. Financial Risk Management Continued

(e) Fair Value Estimation

For disclosure purposes only, the fair values of financial assets and financial liabilities as at 30 June 2022 and 30 June 2021 are presented in the table under Note 3(a)(ii) and can be compared to their carrying values as presented in the consolidated statement of financial position. Fair values are those amounts at which an asset could be exchanged, or a liability settled, between knowledgeable, willing parties in an arm's length transaction. Fair values estimated for disclosure purposes are based on information that is subject to judgement, where changes in assumptions may have a material impact on the amounts estimated.

The following summarises the significant methods and assumptions used in estimating fair values of financial assets and financial liabilities for disclosure purposes:

Cash and Cash Equivalents

The carrying amount is fair value due to the liquid nature of these assets.

Receivables

The carrying amounts of current receivables are assumed to approximate their fair values due to their short-term nature.

Security Deposits

The carrying amounts of security deposits are assumed to represent their fair values based on their likely realisability profile.

Trade and Other Payables

Due to the nature of these financial liabilities, their carrying amounts are a reasonable approximation of their fair values.

Lease Liabilities

Fair value is calculated based on the present value of the lease payments expected to be paid over the lease term, discounted using the interest rate implicit in the lease or, if the rate cannot be readily determined, the Group's estimated incremental borrowing rate.

Derivative Financial Instruments – Cash Flow Hedges

The fair value of derivative financial instruments designated as cash flow hedges are obtained from third party valuations. The fair value is determined using valuation techniques which maximise the use of observable market data.

Other Financial Liabilities – Embedded Derivative

The fair value of the contingent consideration was estimated calculating the present value of the future expected cash outflows. The estimates are based on the Group's internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts. A discount rate of 2.38% and 2% inflation factor has also been applied.

Fair value measurement

The Group uses the following hierarchy for determining and disclosing the fair value of financial instruments by valuation technique:

- Level 1: fair value measurements are those derived from quoted prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2: fair value measurements are those derived from inputs other than quoted prices included within Level 1 which are observable for the asset or liability, either directly or indirectly; and
- Level 3: fair value measurements are those derived from valuation techniques which include inputs for the asset or liability that are not based on observable market data.

All of the Group's financial instruments were valued using the Level 2 valuation technique.

Note 4. Revenue and Other Income

	CONSOLIDATED 2022 US$'000	2021 US$'000
(a) Revenue		
Crude oil sales	**385,074**	170,809
Total revenue from contracts with customers	**385,074**	170,809
(b) Other Income		
Interest income	**150**	286
Net gain on disposal of non-current assets	**639**	19
Total other income	**789**	305

Note 5. Expenses

	CONSOLIDATED 2022 US$'000	2021 US$'000
(a) Cost of sales		
Operating costs	**57,184**	38,393
Royalties	**41,521**	18,972
Depreciation and amortisation – oil and gas assets	**99,355**	64,962
Change in inventories	**(6,356)**	(10,952)
Total cost of sales	**191,704**	111,375
(b) Business development and transition costs		
Baúna transaction costs (refer (i) below)	**–**	15,748
Business development and other project costs	**3,362**	1,816
Total business development and transition costs	**3,362**	17,564

(i) Prior year represents costs incurred on transition, development initiatives and other project activities associated with Baúna prior to the acquisition.

	CONSOLIDATED 2022 US$'000	2021 US$'000
(c) Exploration expenses		
Exploration and evaluation expenditure expensed	**3,196**	3,326
Exploration and evaluation expenditure impaired	**–**	90
Total exploration and evaluation expenditure expensed or impaired	**3,196**	3,416
(d) Finance costs		
Finance charges on lease liabilities	**16,859**	12,501
Discount unwinding on net present value of provision for restoration	**2,366**	942
Interest expense	**2,138**	958
Other finance costs	**1,346**	–
Total finance costs	**22,709**	14,401
(e) Other Expenses		
Corporate	**15,352**	12,250
Realised losses on cash flow hedges	**11,819**	–
Legal settlement (refer (i) below)	**–**	9,600
Depreciation and amortisation – non-oil and gas assets	**728**	744
Share-based payments expense	**5,691**	4,906
Loss on disposal of non-current assets	**38**	9
Write-down of inventory to net realisable value	**–**	577
Other expenses	**186**	460
Total other expenses	**33,814**	28,546

(i) Relates to the Company's wholly owned branch, KEI (Peru Z-38) Pty Ltd, Sucursal del Peru, without any admission of liability, entering into a deed of settlement and release in respect of its dispute with Pitkin Petroleum Peru Z-38 SRL (Pitkin) relating to Block Z-38, offshore Peru. Under the deed of settlement and release, Pitkin has agreed to full and final settlement of all claims of Pitkin and its associates in connection with Block Z-38 with settlement paid in the year ended 30 June 2022.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 6. Income Tax

	NOTE	CONSOLIDATED 2022 US$'000	2021 US$'000
(a) Income Tax Recognised in the Consolidated Statement of Profit or Loss and Other Comprehensive Income			
Tax income (expense) comprises:			
Current income tax		**(39,299)**	(15,321)
Current income tax under/(over)		**19**	(88)
Deferred income tax		**64,667**	47,666
Total income benefit		**25,387**	32,257
The prima facie tax on loss before income tax is reconciled to tax income as follows:			
Prima facie tax benefit on loss before income tax, calculated at the Australian tax rate of 30%		**26,951**	8,362
(Add)/subtract the tax effect of:			
Share-based payments expense (non-cash)		**(1,089)**	(910)
Non-deductible legal settlement		**–**	(2,880)
Other non-deductible items		**(2,756)**	(3,582)
Tax losses and temporary tax differences not recognised		**(184)**	(961)
Adjustment for current tax of previous financial years		**19**	(88)
Difference in overseas tax rates		**2,747**	(665)
Recognition of temporary differences and tax losses not previously brought to account		**–**	20,701
Foreign exchange differences		**(301)**	11,952
Non-assessable income		**–**	328
Total income tax benefit		**25,387**	32,257
(b) Amounts Recognised Directly in Equity			
Aggregate current and deferred tax arising during the financial year and not recognised in net profit or loss, but directly debited or credited in equity:			
Deferred tax – credited directly in contributed equity	24(b)	**–**	143
Deferred tax – credited directly in hedging reserves	24(d)(iii)	**21,217**	–

	CONSOLIDATED				
	BALANCE AS AT 1 JULY 2021 US$'000	CHARGED (CREDITED) TO PROFIT OR LOSS US$'000	CHARGED (CREDITED) DIRECTLY TO EQUITY US$'000	NET FOREIGN CURRENCY DIFFERENCE ON TRANSLATION OF FINANCIAL STATEMENTS TO PRESENTATION CURRENCY US$'000	BALANCE AS AT 30 JUNE 2022 US$'000
(c) Deferred Tax Balances					
Temporary differences					
Provisions and accruals	8,317	11,374	–	(78)	**19,613**
Equity raising transaction costs	249	(80)	–	(17)	**152**
Unrealised foreign currency (gains)/losses/translation adjustment	5,870	(4,491)	–	253	**1,632**
Fair value movement of financial liabilities	2,255	77,220	–	–	**79,475**
Farm-out expenditures	97	–	–	(8)	**89**
Right-of-use assets	(105,172)	9,812	–	13	**(95,347)**
Lease liabilities	106,710	(8,518)	–	(20)	**98,172**
Hedge premium	–	(4,519)	–	–	**(4,519)**
Net changes of cash flow hedges	–	–	21,217	–	**21,217**
Other	3	275	–	–	**278**
Total temporary differences	18,329	81,073	21,217	143	**120,762**
Unused tax losses					
Tax losses	16,424	(14,085)	–	(119)	**2,220**
Total unused tax losses	16,424	(14,085)	–	(119)	**2,220**
Net deferred tax assets/ (liabilities)	34,753	66,988	21,217	24	**122,982**
Presented in the consolidated statement of financial position as follows:					
Deferred tax assets	36,528				**122,982**
Deferred tax liabilities	(1,775)				**–**

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
(d) Unrecognised Deferred Tax Assets		
A deferred tax asset has not been recognised in the consolidated statement of financial position as the benefits of which will only be realised if the conditions for deductibility set out in Note 1(f) occur:		
Unrecognised temporary tax differences relating to deferred tax assets at a tax rate of 34%	**18,031**	16,982
Tax losses: Peruvian operating losses at a tax rate of 32%	**6,335**	6,168
Potential tax income	**24,366**	23,150

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 6. Income Tax Continued

PRRT

PRRT applies to all the Group's Australian petroleum projects in offshore areas under the *Petroleum Resource Rent Tax Assessment Act 1987*, other than some specific production licences. PRRT is assessed on a project basis or production licence area and will be levied on the taxable profits of a relevant petroleum project at a rate of 40%. Certain specified undeducted expenditures are eligible for compounding. The expenditures can be compounded annually at set rates and the compounded amount can be deducted against assessable receipts in future financial years.

An application for consent to surrender petroleum exploration permit WA-482-P, the sole Australian permit held by the Group, was submitted to the National Offshore Petroleum Titles Administrator during the financial year. As a result of this, the Group estimates that it has incurred compounded carried forward undeducted PRRT expenditure in excess of accounting carrying values as at 30 June 2022 of $Nil (2021: $29,143k). The resulting deferred tax asset that has not been recognised in the consolidated statement of financial position was $Nil (2021: 8,160k).

Note 7. Remuneration of External Auditors

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Remuneration received or due and receivable by the external auditor of the Company for:		
(a) PricewaterhouseCoopers Australia		
(i) Audit and other assurance services		
Audit and review of financial statements	**181**	195
Other assurance services	**36**	–
Total remuneration for audit and other assurance services	**217**	195
(ii) Other services		
All other services	**–**	30
Total remuneration of PricewaterhouseCoopers Australia	**–**	225
(b) Related Practices of PricewaterhouseCoopers Australia		
(i) Audit and other assurance services		
Audit and review of financial statements	**130**	118
Total remuneration for audit and other assurance services of related practices of PricewaterhouseCoopers Australia	**130**	118
Total remuneration of external auditors	**347**	343

Note 8. Dividends

There were no ordinary dividends declared or paid during the financial year by the Group (2021: $Nil).

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Balance of franking account available for subsequent reporting periods	**12,436**	12,927

The above amount is calculated from the balance of the Company's franking account as at the end of the financial year. Franking credits are based on the Australian tax rate of 30%.

Note 9. Earnings Per Share

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Profit (loss) for the financial year used to calculate basic and diluted earnings per ordinary share:	**(64,451)**	4,384
(a) Basic profit (loss) per ordinary share	**(0.1159)**	0.0079
(b) Diluted profit (loss) per ordinary share*	**(0.1159)**	0.0077
* Diluted loss per ordinary share equates to basic loss per ordinary share in the current financial year because a loss per ordinary share is not considered dilutive for the purposes of calculating earnings per share pursuant to AASB 133 *'Earnings per Share'*		
Weighted average number of ordinary shares on issue during the financial year used in calculating basic earnings per ordinary share:	**555,904,067**	553,552,881
Weighted average number of potential ordinary shares:	**12,154,223**	13,525,080
Weighted average number of ordinary shares and potential ordinary shares used in calculating diluted earnings per ordinary share (excluding anti-dilutive share options outstanding):	**568,058,290**	567,077,961
Weighted average number of anti-dilutive share options:	**–**	4,750,911

Potential ordinary shares

Share options and performance rights over unissued ordinary shares of the Company outstanding at the end of the financial year are considered to be potential ordinary shares and have been included in the determination of diluted earnings per ordinary share to the extent to which they are dilutive. The potential ordinary shares have not been included in the determination of basic earnings per ordinary share.

Note 10. Cash and Cash Equivalents

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Cash at bank and on hand	**157,683**	133,209
Total cash and cash equivalents	**157,683**	133,209

Note 11. Receivables

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Trade debtors – crude oil sales	**55,979**	33,831
Other receivables	**357**	331
Total current receivables	**56,336**	34,162

(a) Financial Risk Management

Information concerning the Group's exposure to financial risks on receivables is set out in Note 3.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 12. Inventories

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Current		
Petroleum inventories	**17,308**	10,952
Casing and other drilling inventory	**2,095**	–
Total current inventories	**19,403**	10,952
Non-current		
Casing and other drilling inventory	**5,828**	6,536
Total non-current inventories	**5,828**	6,536

Note 13. Security Deposits

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Current		
Karoon Peru Pty Ltd, Sucursal del Peru	**–**	62
Karoon Petróleo & Gas Ltda (refer note (a) below)	**325**	147
Total current security deposits	**325**	209
Non-current		
Karoon Petróleo & Gas Ltda (refer note (b) below)	**1,182**	1,237
Karoon Energy Ltd (refer note (c) below)	**155**	169
Total non-current security deposits	**1,337**	1,406

(a) Bonds

Cash deposits are held as bonds predominately for the Group's compliance with its obligations in respect of agreements for the guarantee (refer Note 28) of payment obligations for various accommodation in Brazil.

(b) Guarantee Bond

The Group has provided the ANP a letter of credit (refer Note 28) to carry out the minimum work program in relation to exploration in Santos Basin Block S-M-1537. The letter of credit is fully funded by way of payment of a security deposit, which will be released once the work program is met.

(c) Bank Guarantees

Cash deposits are held as security against bank guarantee facilities for bank guarantees (refer Note 28) given to lessors for the Group's compliance with its obligations in respect of lease rental agreements for office premises.

(d) Financial Risk Management

Information concerning the Group's exposure to financial risks on security deposits is set out in Note 3.

Note 14. Other Assets

	CONSOLIDATED 2022 US$'000	CONSOLIDATED 2021 US$'000
Current		
Prepayments	**9,312**	2,890
Sundry assets	**2,480**	2,427
Total current other assets	**11,792**	5,317
Non-current		
Prepayments	**1,277**	–
Total non-current other assets	**1,277**	–

Note 15. Oil and Gas Assets

	NOTE	PRODUCTION ASSET US$'000	DEVELOPMENT ASSET US$'000	RIGHT-OF-USE ASSETS US$'000	CONSOLIDATED TOTAL US$'000
At 30 June 2021					
At cost		448,492	19,020	333,872	801,384
Accumulated depreciation		(36,827)	–	(28,135)	(64,962)
Carrying amount at end of financial year		411,665	19,020	305,737	736,422
Financial year ended 30 June 2022					
Balance at beginning of financial period		411,665	19,020	305,737	736,422
Additions	26(c)	69,277	22,739	20,799	112,815
Borrowing costs capitalised		–	4,755	–	4,755
Depreciation expense		(54,950)	–	(44,405)	(99,355)
Impact of increase in discount rate on provision for restoration at year-end	20(b)	(21,595)	–	–	(21,595)
Carrying amount at end of financial year		404,397	46,514	282,131	733,042
At 30 June 2022					
At cost		**496,174**	**46,514**	**354,671**	**897,359**
Accumulated depreciation		**(91,777)**	**–**	**(72,540)**	**(164,317)**
Carrying amount at end of financial year		**404,397**	**46,514**	**282,131**	**733,042**

(i) The capitalised borrowing costs relate to an apportionment of the fees incurred in connection with the syndicated loan facility (refer Note 22) relating to the Patola development, which meets the definition of a qualifying asset.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 16. Property, Plant and Equipment

	NOTE	PLANT AND EQUIPMENT US$'000	RIGHT-OF-USE ASSETS US$'000	CONSOLIDATED TOTAL US$'000
At 30 June 2021				
At cost		8,722	1,681	10,403
Accumulated depreciation		(1,549)	(594)	(2,143)
Carrying amount at end of financial year		7,173	1,087	8,260
Financial year ended 30 June 2022				
Balance at beginning of financial year		7,173	1,087	8,260
Additions	26(c)	5,005	943	5,948
Disposals		(52)	(127)	(179)
Depreciation expense		(234)	(447)	(681)
Net foreign currency differences		(37)	(54)	(91)
Carrying amount at end of financial year		11,855	1,402	13,257
At 30 June 2022				
At cost		**13,638**	**2,443**	**16,081**
Accumulated depreciation		**(1,783)**	**(1,041)**	**(2,824)**
Carrying amount at end of financial year		**11,855**	**1,402**	**13,257**

Note 17. Intangible Assets

		CONSOLIDATED	
	NOTE	2022 US$'000	2021 US$'000
The reconciliation of the carrying amounts for computer software is set out below:			
Balance at beginning of financial year		**102**	211
Additions	26(c)	**23**	34
Disposal		**(35)**	(39)
Amortisation expense		**(47)**	(106)
Net foreign currency differences		**(3)**	2
Carrying amount at end of financial year		**40**	102

Note 18. Exploration and Evaluation Expenditure Carried Forward

		CONSOLIDATED	
	NOTE	2022 US$'000	2021 US$'000
The reconciliation of exploration and evaluation expenditure carried forward is set out below:			
Balance at beginning of financial year		**40,853**	41,204
Additions	26(c)	**1,389**	1,932
Transfer to development assets (refer note (a) below)	26(c)	**(1,405)**	(1,553)
Exploration and evaluation expenditure impaired	5(c)	**–**	(90)
Net foreign currency differences		**–**	(640)
Total exploration and evaluation expenditure carried forward		**40,837**	40,853

(a) Exploration and evaluation expenditure relating to the Patola discovery, which has been transferred to development assets following declaring of a FID during the current financial year.

The expenditure is carried forward on the basis that exploration and evaluation activities in the areas of interest have not reached a stage that permits reasonable assessment of the existence or otherwise of economically recoverable reserves and active and significant operations in, or in relation, to the areas is continuing. The future recoverability of the carrying amount of capitalised exploration and evaluation expenditure is dependent on successful development and commercial exploitation or, alternatively, the sale of the respective areas of interest.

Note 19. Trade and Other Payables

	CONSOLIDATED 2022 US$'000	2021 US$'000
Trade payables	**60,879**	30,286
Petrobras deferred consideration	**–**	42,422
Sundry payables and accruals	**5,328**	2,933
Cash-settled share-based payments	**2,095**	533
Total current trade and other payables	**68,302**	76,174
Non-current (unsecured)		
Sundry payables and accruals	**5,690**	2,761
Cash-settled share-based payments	**1,073**	1,500
Total non-current trade and other payables	**6,763**	4,261

(a) Financial Risk Management

Information concerning the Group's exposure to financial risks on trade and other payables is set out in Note 3.

Note 20. Provisions

	CONSOLIDATED 2022 US$'000	2021 US$'000
Current		
Provision for long service leave (refer note (a) below)	**368**	457
Total current provision	**368**	457
Non-current		
Provision for long service leave (refer note (a) below)	**11**	82
Provision for restoration (refer note (b) below)	**139,474**	158,703
Total non-current provisions	**139,485**	158,785

(a) Provision for Long Service Leave

A provision was recognised for employee entitlements relating to long service leave. The measurement and recognition criteria relating to long service leave entitlements are as described in Note 1(t).

The current portion of this provision includes all the unconditional entitlements to long service leave where employees have completed the required period of service and also those where employees are entitled to pro-rata payments in certain circumstances.

(b) Reconciliation of provision for restoration

	CONSOLIDATED 2022 US$'000	2021 US$'000
Balance at beginning of financial period	**158,703**	–
Additions (refer note (i) below)	**–**	169,384
Discount unwinding on provision for restoration	**2,366**	942
Impact of increase in discount rate at year-end	**(21,595)**	(11,623)
Total provision for restoration	**139,474**	158,703

(i) A provision was recognised in the prior period for a Brazilian restoration obligation relating to the acquisition of Baúna. The measurement and recognition criteria relating to restoration obligations are as described in Note 1(t).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 21. Leases

	CONSOLIDATED 2022 US$'000	CONSOLIDATED 2021 US$'000
Current	**43,741**	45,393
Non-current	**245,146**	267,447
Total lease liabilities	**288,887**	312,840
Reconciliation		
Balance at beginning of financial year	**312,840**	1,516
Acquisitions (refer note (i) below)	**–**	329,815
Remeasurements	**20,799**	4,109
Additions	**924**	–
Disposals	**(201)**	(45)
Adjustment to fixed lease payments	**(766)**	(1,107)
Accretion of interest	**16,859**	12,501
Payments	**(61,455)**	(34,090)
Net foreign currency differences	**(113)**	141
Total lease liabilities	**288,887**	312,840

(i) A right-of-use asset was recognised as part of the oil and gas assets acquired during the prior period in relation to an FPSO Charter agreement.

Note 22. Borrowings

	CONSOLIDATED 2022 US$'000	CONSOLIDATED 2021 US$'000
Non-Current		
Syndicated loan facility – secured	**30,000**	–
Less transaction costs (i)	**(2,856)**	–
Total non-current borrowings	**27,144**	–

(i) Includes remaining unamortised transaction costs associated with the syndicated loan facility and excludes costs that have been capitalised as part of Oil and Gas Assets in relation to qualifying assets.

During November 2021, Karoon Energy Ltd's wholly owned subsidiary, Karoon Petróleo & Gás Ltda, reached financial close on a new reserve-based, non-recourse, syndicated loan facility with Deutsche Bank AG, ING Belgium SA/NV, Macquarie Bank Limited and Shell Western Supply and Trading Limited. In April 2022, an additional accordion facility, contemplated by the syndicated loan facility, was established.

The facility is available to fund permitted expenditure in connection with the Patola field development and the Baúna intervention campaign, facility and treasury costs and deferred consideration payable to Petrobras of up to $44.5m.

The facility is secured over the shares in and assets of Karoon Petróleo & Gás Ltda, including its interest in the Baúna BM-S-40 concession.

The total available amount under the facility, including the accordion, is $210 million. At 30 June 2022, $30 million has been drawn down, with $180m remaining undrawn.

Interest is charged at a 4.25% margin over SOFR per annum and a commitment fee is charged on undrawn but committed and available amounts at 1.7% per annum and an additional 0.85% per annum on any committed but unavailable amounts. The facility has a final maturity date of the earlier of 31 March 2025 or the quarter where the remaining reserves are forecast to be ≤ 25% of the initial approved reserves. Semi-annual repayments of $40m under the facility (excluding the accordion) commence on 30 September 2023 to the final maturity date.

Karoon is also required to enter into oil hedging to ensure forecasted oil production is within a minimum and maximum hedge ratio.

The Group has complied with all loan covenants throughout the reporting period.

Note 23. Other Financial Liabilities

	CONSOLIDATED 2022 US$'000	2021 US$'000
Current		
Derivative financial instruments – cash flow hedges (i)	**40,767**	–
Embedded derivative – contingent consideration payable (ii)	**84,631**	–
Total current other financial liabilities	**125,398**	–
Non-Current		
Derivative financial instruments – cash flow hedges (i)	**8,345**	–
Embedded derivative – contingent consideration payable (ii)	**213,649**	71,161
Total non-current other financial liabilities	**221,994**	71,161
Total other financial liabilities	**347,392**	71,161

(i) During the period, the Group entered into Brent oil price derivative hedges, via a collar structure consisting of bought put and sold call options covering the period from December 2021 to March 2024. The purpose of the hedges is to protect operating cash flows from a portion of crude oil sales against the risk of lower oil prices while retaining significant exposure to oil price upside. The hedges are also a requirement of the syndicated loan facility entered into during the period (refer Note 22).

The bought put and sold call options have been designated as cash flow hedges, and in the current period, changes in the fair value of the options and costs of hedging of $62,491k pre-tax ($41,274k net of tax) have been recognised in the hedging reserves within equity (refer Note 24), which includes $1,520k pre-tax that has been reclassified to profit and loss. No losses were recognised in profit and loss for hedge ineffectiveness during the period.

At 30 June 2022, the Group had the following outstanding hedges:

	BOUGHT PUT STRIKE (US$/BBL)	PUT VOLUME ('000 BBL)	SOLD CALL AVERAGE STRIKE (US$/BBL)	CALL VOLUME ('000 BBL)
2023	65	2,586	84.5	2,497
2024	65	2,040	91.8	1,578
		4,626		4,075

	CONSOLIDATED 2022 US$'000	2021 US$'000
(ii) Reconciliation of contingent consideration payable		
Balance at beginning of financial year	**71,161**	–
Additions (refer note (a) below)	**–**	64,529
Unrealised fair value changes recognised in profit or loss during the period	**227,119**	6,632
Total contingent consideration payable at fair value	**298,280**	71,161

(a) The contingent consideration arrangement for the acquisition of Baúna requires Karoon's wholly owned subsidiary, Karoon Petróleo & Gás Ltda., to pay Petrobras contingent consideration of up to US$285 million.

The contingent consideration accrues interest at 2% per annum from 1 January 2019 with any amounts payable by 31 January after the completion of the relevant testing period. The relevant testing periods are each calendar year from 2022 to 2026 inclusive and are based on the achievement of annual average Platts Dated Brent oil prices thresholds commencing at ≥US$50 and ending at ≥US$70 a barrel.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 23. Other Financial Liabilities Continued

After the testing of each year, any amount deemed not payable is cancelled and not carried forward. The amount payable each calendar year excluding interest depending on achievement of certain oil prices is disclosed below:

AVERAGE BRENT PRICE (IN US$ UNITS)	CY2022	CY2023	CY2024	CY2025	CY2026	TOTAL
B < 50	–	–	–	–	–	–
50 <= B < 55	3	3	3	2	2	13
55 <= B < 60	17	17	17	8	4	63
60 <= B < 65	34	34	34	15	6	123
65 <= B < 70	53	53	53	24	10	193
B >= 70	78	78	78	36	15	285

As at 30 June 2022, based on higher current oil prices and industry consensus, the internal Brent oil forecast was revised with the US$70 per barrel threshold triggered over calendar years 2022-2026 and the fair value of the contingent consideration payable to Petrobras revalued upwards by $227.1 million to $298.3 million (30 June 2021: $71 million). $84.6m, the amount payable in respect of the 2022 calendar year, and due for payment in January 2023, has been recognised as a current liability.

A discount rate of 2.38% and 2% interest per annum has been applied in the calculation of the present value at 30 June 2022. The fair value of the contingent consideration is estimated calculating the present value of the future expected cash outflows. The estimates are based on the Group's internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts.

Note 24. Contributed Equity and Reserves Within Equity

(a) Contributed Equity

	CONSOLIDATED		CONSOLIDATED	
	2022 NUMBER	2021 NUMBER	2022 US$'000	2021 US$'000
Ordinary shares, fully paid	**558,085,352**	553,770,529	**907,514**	905,138
Total contributed equity	**558,085,352**	553,770,529	**907,514**	905,138

Ordinary shares have no par value, and the Company does not have a limited amount of authorised capital.

Voting rights of shareholders are governed by the Company's Constitution. In summary, on a show of hands every holder of ordinary shares present at a meeting in person or by proxy is entitled to one vote, and upon a poll each such attending shareholder is entitled to one vote for every fully paid ordinary share held.

Ordinary shares participate in dividends as declared from time to time and the proceeds on winding up of the Company in proportion to the number of fully paid ordinary shares held.

(b) Movement in Ordinary Shares

DATE	DETAILS	NOTE	NUMBER OF ORDINARY SHARES	US$'000
1 July 2020	Opening balance in previous financial year		552,984,693	905,281
	Deferred tax credit recognised directly in equity		–	(143)
	Performance rights conversion	31(c)	785,836	–
30 June 2021	Balance at end of financial year		553,770,529	905,138
	Exercise of options		**2,383,899**	**2,376**
	Performance rights conversion	31(c)	**1,930,924**	**–**
30 June 2022	Balance at end of financial year		**558,085,352**	**907,514**

(c) Capital Management

The Board of Directors controls the capital of the Company in order to ensure that the Group can fund its operations and continue as a going concern. The aim is to maintain a capital structure that ensures the lowest cost of capital to the Company.

The Chief Executive Officer and Managing Director manages the Company's capital by monitoring future rolling cash flows and adjusting its capital structure, as required, in consultation with the Board of Directors to meet Group business objectives. As required, the Group will balance its overall capital structure through the issue of new ordinary shares, share buy-backs and utilising short-term and long-term loan facilities when necessary.

There were no externally imposed capital management restrictions on the Group during the financial year.

(d) Reserves Within Equity

(i) Share-based Payments Reserve

The share-based payments reserve is used to recognise the grant date fair value of equity-settled share-based payments to Executive Directors, other key management personnel and employees as part of their remuneration, as described in Note 1(s).

(ii) Foreign Currency Translation Reserve

The foreign currency translation reserve is used to recognise exchange differences arising from the translation of financial statements into the presentation currency as described in Note 1(e). The relevant amounts included in the foreign currency translation reserve will be recognised in the consolidated statement of profit or loss and other comprehensive income when each relevant investment in the entity is disposed.

(iii) Hedging Reserves

During the period, the Group entered into Brent oil price derivative hedges. Refer to Note 23(i) for more details.

The Group designates only the change in fair value of the spot element of the derivative transaction contracts (the intrinsic value of the option) as the hedging instrument in cash flow hedging relationships. The change in fair value of the value of the option contract in time is separately accounted for as a cost of hedging and recognised in a costs of hedging reserve within equity.

The following is a reconciliation of the movement of the hedging reserves:

	COST OF HEDGING RESERVE US$'000	INTRINSIC VALUE OF OPTIONS US$'000	TOTAL HEDGING RESERVES US$'000
Balance at beginning of financial year	–	–	–
Change in fair value of cash flow hedges and cost of hedging recognised in OCI	**58,313**	**(122,324)**	**(64,011)**
Reclassified from OCI to profit or loss – included in other expenses	**1,520**	–	**1,520**
Deferred tax	**(20,373)**	**41,590**	**21,217**
Balance at end of financial year	**39,460**	**(80,734)**	**(41,274)**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 25. Subsidiaries

The consolidated financial statements incorporate the assets, liabilities and results of the following subsidiaries in accordance with the accounting policy described in Note 1(b):

NAME	COUNTRY OF INCORPORATION OR REGISTRATION	BUSINESS ACTIVITIES CARRIED ON IN	PERCENTAGE OF EQUITY AND VOTING INTERESTS HELD BY THE GROUP 2022 %	2021 %
Parent Company:				
Karoon Energy Ltd	Australia	Australia		
Unlisted subsidiaries of Karoon Energy Ltd:				
Karoon Energy International Pty Ltd	Australia	Australia	**100**	100
Karoon Gas Browse Basin Pty Ltd	Australia	Australia	**100**	100
Karoon Gas (FPSO) Pty Ltd	Australia	Australia	**100**	100
Unlisted subsidiaries of Karoon Energy International Pty Ltd:				
KEI (Brazil Santos) Pty Ltd	Australia	Australia	**100**	100
Karoon Peru Pty Ltd	Australia	Australia	**100**	100
KEI (Peru Z 38) Pty Ltd	Australia	Australia	**100**	100
Unlisted subsidiary of KEI (Brazil Santos) Pty Ltd:				
Karoon Petróleo & Gás Ltda	Brazil	Brazil	**100**	100
Branch of KEI Peru Pty Ltd:				
Karoon Peru Pty Ltd, Sucursal del Peru (in liq)	Peru	Peru	**100**	100
Branch of KEI (Peru Z 38) Pty Ltd:				
KEI (Peru Z-38) Pty Ltd, Sucursal del Peru	Peru	Peru	**100**	100

Note 26. Segment Information

(a) Description of Segments

The Group has identified its operating segments based on the internal reports that are reviewed and used by the Group's Executive Management Team (identified as the 'chief operating decision maker') in assessing performance and in determining the allocation of resources.

The operating segments are based on the Group's geographical location of its operations.

The Group has identified operating segments based on the following two geographic locations:

- Australia – in which the Group was involved in the exploration and evaluation of hydrocarbons in an offshore exploration permit area: WA-482-P; and
- Brazil – in which the Group is currently involved in the exploration, development and production of hydrocarbons in four offshore blocks: Block BM-S-40, Block S-M-1037, Block S-M-1101, and Block S-M-1537;

At 30 June 2021, the Group identified operating segments based on three geographical locations, Australia, Peru & Brazil. The Peru segment effectively ceased operations from 1 July 2021, when the Group decided to relinquish its explorations interests in Peru.

'All other segments' include amounts of a corporate nature not specifically attributable to an operating segment, including costs associated with closure of the Group's Peruvian Branches as noted above.

The accounting policies of the reportable operating segments are the same as the Group's accounting policies.

Segment revenues and results do not include transfers between segments as intercompany balances are eliminated on consolidation.

Employee benefits expense and other expenses, which are associated with exploration and evaluation activities and specifically relate to an area of interest, are allocated to the area of interest and are either expensed or capitalised using the successful efforts method of accounting.

The amounts provided to the chief operating decision maker with respect to total assets and total liabilities are measured in a manner consistent with that of the consolidated financial statements. Reportable segment assets and segment liabilities are equal to consolidated total assets and total liabilities respectively. These assets and liabilities are allocated in accordance with the operations of the segment.

(b) Operating Segments

SEGMENT PERFORMANCE	AUSTRALIA US$'000	BRAZIL US$'000	ALL OTHER SEGMENTS US$'000	CONSOLIDATED US$'000
Result for financial year ended 30 June 2022				
Revenue	–	385,074	–	385,074
Other income	62	222	505	789
Total segment revenue	**62**	**385,296**	**505**	**385,863**
Expenses				
Business development and transition costs	(348)	(3,013)	(1)	(3,362)
Cost of sales	–	(191,704)	–	(191,704)
Depreciation and amortisation expense – non-oil and gas assets	(303)	(411)	(14)	(728)
Exploration expenses	(304)	(2,789)	(103)	(3,196)
Finance costs	(52)	(22,657)	–	(22,709)
Realised losses on cash flow hedges	–	(11,819)	–	(11,819)
Corporate expenses	(10,862)	(3,607)	(883)	(15,352)
Net foreign currency gains (losses)	4,560	2,083	(440)	6,203
Change in fair value of contingent consideration	–	(227,119)	–	(227,119)
Share-based payments expense	(3,746)	(1,945)	–	(5,691)
Other	–	(109)	(115)	(224)
Profit/ (loss) before income tax	(10,993)	(77,794)	(1,051)	(89,838)
Income tax benefit	2,429	22,958	–	25,387
Profit/ (loss) for financial year	(8,564)	(54,836)	(1,051)	(64,451)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 26. Segment Information Continued

SEGMENT PERFORMANCE	AUSTRALIA US$'000	BRAZIL US$'000	PERU US$'000	ALL OTHER SEGMENTS US$'000	CONSOLIDATED US$'000
Result for financial year ended 30 June 2021					
Revenue	–	170,809	–	–	170,809
Other income	93	206	6	–	305
Total segment revenue	93	171,015	6	–	171,114
Expenses					
Business development and transition costs	(81)	(17,386)	(97)	–	(17,564)
Cost of sales	–	(111,375)	–	–	(111,375)
Depreciation and amortisation expense – non-oil and gas assets	(287)	(271)	(186)	–	(744)
Exploration expenses	254	(2,580)	(1,090)	–	(3,416)
Finance costs	(66)	(14,331)	(4)	–	(14,401)
Corporate expenses	(7,519)	(3,707)	(1,024)	–	(12,250)
Inventory write-down	–	(577)	–	–	(577)
Net foreign currency losses	(16,839)	154	(368)	–	(17,053)
Change in fair value of contingent consideration	–	(6,632)	–	–	(6,632)
Legal settlement	–	–	(9,600)	–	(9,600)
Share-based payments expense	(2,873)	(2,033)	–	–	(4,906)
Other	–	(158)	(311)	–	(469)
Profit/ (loss) before income tax	(27,318)	12,119	(12,674)	–	(27,873)
Income tax benefit	7,816	24,441	–	–	32,257
Profit/ (loss) for financial year	(19,502)	36,560	(12,674)	–	4,384

FINANCIAL YEAR ENDED 30 JUNE 2022	AUSTRALIA US$'000	BRAZIL US$'000	ALL OTHER SEGMENTS US$'000	CONSOLIDATED US$'000
Total segment assets	**49,293**	**1,114,675**	**171**	**1,164,139**
Total segment liabilities	**4,817**	**883,118**	**3**	**887,938**

FINANCIAL YEAR ENDED 30 JUNE 2021	AUSTRALIA US$'000	BRAZIL US$'000	PERU US$'000	ALL OTHER SEGMENTS US$'000	CONSOLIDATED US$'000
Total segment assets	64,560	947,806	1,590	–	1,013,956
Total segment liabilities	6,267	617,632	9,807	–	633,706

(c) Other Segment Information

Additions to non-current assets, other than financial assets (refer Note 3), during the reporting periods were:

FINANCIAL YEAR ENDED 30 JUNE 2022	AUSTRALIA US$'000	BRAZIL US$'000	ALL OTHER SEGMENTS US$'000	CONSOLIDATED US$'000
Property, plant and equipment^	**231**	**5,717**	**–**	**5,948**
Oil and gas assets^	**–**	**112,815**	**–**	**112,815**
Intangible assets	**22**	**1**	**–**	**23**
Exploration and evaluation expenditure carried forward	**–**	**–**	**–**	**–**

^ Includes right-of-use assets.

FINANCIAL YEAR ENDED 30 JUNE 2021	AUSTRALIA US$'000	BRAZIL US$'000	PERU US$'000	ALL OTHER SEGMENTS US$'000	CONSOLIDATED US$'000
Property, plant and equipment^	43	6,039	–	–	6,082
Oil & gas assets^	–	813,006	–	–	813,006
Intangible assets	34	–	–	–	34
Exploration and evaluation expenditure carried forward	–	379	–	–	379

^ Includes right-of-use assets.

Note 27. Joint Operations

The Group has an equity interest in the following joint operations as at 30 June 2022 as follows:

PETROLEUM TENEMENT	BUSINESS ACTIVITIES CARRIED ON IN	UNINCORPORATED EQUITY INTEREST (%) 2022 %	2021 %	PRINCIPAL ACTIVITIES	OPERATOR OF JOINT OPERATION
WA-482-P	Northern Carnarvon Basin, Australia	**50**	50	Exploration and evaluation	Santos WA Energy Limited
Block Z-38	Tumbes Basin, Peru	**–**	75	Exploration and evaluation	KEI (Peru Z-38) Pty Ltd, Sucursal del Peru

An application for consent to surrender Petroleum Exploration Permit WA-482-P was submitted to the National Offshore Petroleum Titles Administrator (NOPTA) during the financial year. As at year end, the application had been screened, assessed and was with the Joint Authority for a decision.

The following amounts represented the Group's share of assets, liabilities, revenues and expenses employed in joint operations. The amounts are included in the consolidated financial statements, in accordance with the accounting policy described in Note 1(v), under the following classifications:

	CONSOLIDATED 2022 US$'000	2021 US$'000
Cash and cash equivalents	**–**	303
Inventory	**–**	135
Trade and other payables (current)	**(2)**	(233)
Share of net assets employed in joint operations	**(2)**	205
Other expenses	**–**	(1)
Exploration and evaluation expenditure expensed or impaired	**(302)**	(1,133)

There are no contingent liabilities in respect of joint operations as at year end.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 28. Contingent Liabilities and Contingent Assets

(a) Contingent Liabilities

The Group has contingent liabilities as at 30 June 2022 that may become payable in respect of:

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
(i) A Parent Company guarantee totalling BRL117.7 million provided to the ANP in respect of existing decommissioning obligations relating to the Baúna field.	**22,480**	20,866
(ii) Performance guarantee (via a letter of credit) provided to Perupetro SA for Area 73 by the Group (refer Note 13). The performance guarantee was returned and released during July 2021 having met all work commitments and submission of relevant reports to Perupetro SA.	**–**	62
(iii) The Group has provided the ANP a letter of credit (refer Note 13) to carry out the minimum work program in relation to exploration in Santos Basin Block S-M-1537. The Directors are of the opinion that the work program commitments will be satisfied. The letter of credit is fully funded by way of payment of a security deposit, which will be released once the work program is met.	**1,181**	1,237
(iv) Bank guarantees were provided in respect of rental agreements for office premises of the Group. These guarantees may give rise to liabilities in the Group if obligations are not met under these guarantees. The bank guarantees given to lessors are fully funded by way of payment of security deposits (refer Note 13).	**155**	304
(v) Cash deposits (refer Note 13) are held as bonds for the Group's compliance with its obligations in respect of agreements for the guarantee of payment obligations for various accommodation in Brazil and Peru.	**325**	–

(vi) Block Acquisition

As part of the acquisition of Pacific Exploration and Production Corp's equity interest of Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102, S-M-1165 and S-M-1166 during the 2017 financial year, the Group agreed to pay Pacific Exploration and Production Corp. a deferred contingent consideration of $5.0 million payable upon first production reaching a minimum of 1 million barrels of oil equivalent from the Blocks. The deferred contingent obligation has not been provided for as at 30 June 2022, as it is dependent upon uncertain future events.

(vii) Brazilian Local Content

The Concession Contracts for Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102, S-M-1165, S-M-1537 and S-M-1166 require Karoon Petróleo & Gas Ltda to acquire a minimum proportion of goods and services from Brazilian suppliers, with the objective to stimulate industrial development, promote and diversify the Brazilian economy, encourage advanced technology and develop local capabilities. The minimum Brazilian local content requirement under the Concession Contracts during the exploration and appraisal phase is up to 55%. If Karoon Petróleo & Gas Ltda fails to comply with this minimum requirement, Karoon Petróleo & Gas Ltda may be subject to a fine by the ANP.

(viii) Joint Operations

In accordance with normal industry practice, the Group has entered into joint operations with other parties for the purpose of exploring and evaluating its exploration tenements. If a participant to a joint operation defaults and does not contribute its share of joint operation obligations, then the remaining joint operation participants are jointly and severally liable to meet the obligations of the defaulting participant. In this event, the equity interest in the exploration tenements held by the defaulting participant may be redistributed to the remaining joint operation participants.

In the event of a default, a contingent liability exists in respect of expenditure commitments due to be met by the Group in respect of the defaulting joint operation participant.

(ix) Other Matters

There are also legal claims and exposures, which arise from the Group's ordinary course of business. No material loss to the Group is expected to result.

(b) Contingent Assets

The Group has no contingent assets as at 30 June 2022 (30 June 2021: $Nil).

Note 29. Commitments

	CONSOLIDATED 2022 US$'000	2021 US$'000
(a) Capital and Service Expenditure Commitments		
Contracts for capital and service expenditure in relation to assets not provided for in the consolidated financial statements and payable. Note the service commitments as at 30 June 2022 include the provision of services related to the charter of the FPSO acquired as part of the Baúna acquisition.		
Capital commitments for Baúna workovers and Patola Development		
Not later than one year	**75,945**	79,269
Later than one year but not later than five years	**–**	26,691
Total capital commitments	**75,945**	105,960
Service commitments		
Not later than one year	**11,509**	11,990
Later than one year but not later than five years	**31,883**	42,504
Total service commitments	**43,392**	54,494
Total capital and service expenditure commitments	**119,337**	160,454
(b) Exploration Expenditure Commitments		
The Group has guaranteed commitments for exploration expenditure arising from obligations to governments to perform minimum exploration and evaluation work and expend minimum amounts of money pursuant to the award of exploration tenements Block S-M-1537 (30 June 2021: WA-482-P and Block S-M-1537) not provided for in the consolidated financial statements and payable.		
Not later than one year	**–**	102
Later than one year but not later than five years	**3,500**	3,500
Total guaranteed exploration expenditure commitments	**3,500**	3,602
The Group does not have any non-guaranteed government work commitments in relation to these exploration tenements due later than one year but not later than five years (30 June 2021: $15,224k).		
Exploration expenditure commitments, including farm-in, obligations in respect of joint operations are set-out below:		
Not later than one year	**–**	102
Total joint operation guaranteed exploration expenditure commitments	**–**	102

Note, the figures above do not include any commitments in relation to Exploration Blocks S-M-1037 and S-M-1101 relating to the Neon and Goiá light oil discoveries. In accordance with Brazilian regulatory requirements, during January 2019 Karoon submitted both a Final Discovery Evaluation Report and Declaration of Commerciality for the discoveries. This transitioned the Blocks for Brazilian regulatory requirements, from the exploration phase to the development phase, akin to receiving a Retention Licence over the oil discoveries. However, it does not mean that Karoon has reached, nor is compelled to reach, a final investment decision ('FID') to proceed into a Development of the discoveries. Prior to an FID being reached, in April 2022 Karoon committed to drilling a 'control well(s)' to assist with delineating the Neon discovery, confirming reservoir quality and assisting with the planning and design of both development wells and infrastructure. These control well(s) are planned to be drilled in the first half of CY2023 (subject to receipt of relevant approvals), after completion of the Patola development.

Estimates for future exploration expenditure commitments to government are based on estimated well and seismic costs, which will change as actual drilling locations and seismic surveys are completed and are calculated in current dollars on an undiscounted basis. The exploration and evaluation obligations may vary significantly as a result of renegotiations with relevant parties. The commitments may also be reduced by the Group entering into farm-out agreements, which are typical of the normal operating activities of the Group, or by relinquishing exploration tenements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 30. Reconciliation to the Consolidated Statement of Cash Flows

(a) Reconciliation of Loss for Financial Year to Net Cash Flows Used in Operating Activities

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Profit (loss) for financial year	**(64,451)**	4,384
Add (subtract)		
Non-cash items included in loss for financial year:		
Depreciation and amortisation	**100,083**	65,706
Amortisation of finance costs	**464**	–
Change in fair value of derivative financial instruments	**(62,491)**	–
Change in fair value of contingent consideration	**227,119**	6,632
Discount unwinding on provision for restoration and deferred consideration	**2,366**	1,797
Share-based payments expense	**3,632**	3,034
Gain on disposal of right-of-use asset	**(75)**	(1)
Net foreign currency losses (gains)	**(3,019)**	17,092
Items classified as investing/ financing activities:		
Interest paid on deferred consideration	**1,166**	–
Net (gain) loss on disposal of non-current assets	**(526)**	(10)
Net foreign currency gains (losses)	**(466)**	(151)
Exploration and evaluation expenditure impaired or written-off	**–**	90
Write-down of inventory to net realisable value	**–**	577
Change in operating assets and liabilities:		
(Increase) decrease in assets		
Receivables – current	**(22,174)**	(24,783)
Oil inventories	**(6,356)**	(10,952)
Deferred tax assets	**(86,454)**	(36,528)
Other assets	**(6,863)**	(3,673)
Increase (decrease) in liabilities		
Trade and other payables – current	**51**	7,003
Trade and other payables – non-current	**2,502**	4,078
Provisions – current	**(89)**	48
Provisions – non-current	**(71)**	(1)
Current tax liabilities	**1,344**	5,532
Deferred tax liabilities	**19,442**	(10,088)
Derivative financial instruments – cash flow hedges	**49,112**	–
Net cash flows provided by (used in) operating activities	**154,246**	29,786

Note 31. Share-based Payments

The share-based payment plans are described below. There has been no cancellation to a plan during the financial year.

(a) Employee Share Option Plan ('ESOP')

The Company currently only has the 2016 ESOP in place. ESOP options expire up to 4 years after they are granted. The exercise price of ESOP options is based on the volume weighted average price at which the Company's ordinary shares are traded on the ASX during the 20 days of trading before the ESOP options were offered plus a premium to the market price.

Each ESOP option provides eligible employees with the right to acquire one fully paid ordinary share of the Company at the exercise price determined upon grant, or its equivalent value, subject to the achievement of the relevant performance conditions.

Share options granted under the ESOP carry no dividend or voting rights.

If there is a change of control of the Company, for all unexercised ESOP options, a percentage amount of unvested ESOP options may vest on the basis of the pro-rata achievement of pre-determined performance conditions.

During the financial year, the Group did not grant any ESOP options (2021: $Nil) over unissued ordinary shares in the Company to Executive Directors.

The following summary reconciles the outstanding ESOP options over unissued ordinary shares in the Company at the beginning and end of the financial year:

	CONSOLIDATED			
	2022		2021	
	NUMBER	WEIGHTED AVERAGE EXERCISE PRICE A$	NUMBER	WEIGHTED AVERAGE EXERCISE PRICE A$
Balance at beginning of financial year	**4,066,123**	**$1.40**	7,230,019	$1.54
Granted during financial year	**–**	**–**	–	–
Exercised during financial year	**(2,383,899)**	**$1.40**	–	–
Cancelled during financial year	**(906,031)**	**$1.40**	–	–
Cash-settled during financial year	**(776,193)**	**$1.40**	–	–
Expired during financial year	**–**	**–**	–	–
Forfeited during financial year	**–**	**–**	(3,163,896)	$1.73
Balance at end of financial year	**–**	**–**	4,066,123	$1.40
Exercisable at end of financial year	**–**	**–**	–	–

There were no ESOP options outstanding as at 30 June 2022 (30 June 2021: exercise price of A$1.40 with a weighted average remaining contractual life of 365 days).

(b) Fair Value of Share Options

The fair value of each share option issued during previous financial years was estimated on grant date using the Black-Scholes option pricing model. The Black-Scholes option pricing model takes into account the exercise price, the term of the share option, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the share option. The last grant of share options was during the year ended 30 June 2019.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 31. Share-based Payments Continued

(c) Performance Rights Plan ('PRP')

The Company currently has two PRPs in place, the 2016 PRP and 2019 PRP. The 2019 PRP was approved by shareholders at the 2019 Annual General Meeting.

Under the PRP, eligible employees are given performance rights to be issued and allotted fully paid ordinary shares in the Company, or equivalent cash value, for no consideration provided certain conditions have been met. Vesting of STI performance rights is conditional on the achievement of performance measures, over a one-year performance period, and provided the employee remains employed by the Company for an additional year. Vesting of LTI performance rights is conditional on the achievement of performance measures over a three-year performance period. In each case, the Board, on advice from People, Culture and Governance Committee, will be responsible for assessing whether the performance measures have been achieved. When vested, each performance right is convertible into one ordinary share of the Company.

Performance rights granted carry no dividend or voting rights.

If there is a change of control of the Company, for all unexercised performance rights issued pursuant to the Company's PRP, a percentage amount of unvested performance rights may vest on the basis of the pro-rata achievement of pre-determined performance conditions.

During the financial year, the Group granted 577,052 performance rights (2021: 502,989) over unissued ordinary shares in the Company to Executive Directors. The performance rights were provided to the Chief Executive Officer and Managing Director and were subject to approval by shareholders at the 2021 Annual General Meeting. Performance rights issued to Directors are approved on a case-by-case basis by shareholders at relevant general meetings.

The following summary reconciles the outstanding performance rights over unissued ordinary shares in the Company at the beginning and end of the financial year:

	CONSOLIDATED	
	2022 NUMBER	2021 NUMBER
Balance at beginning of financial year	**14,861,486**	10,935,950
Granted during financial year	**2,370,032**	8,847,523
Vested and converted during financial year	**(1,930,924)**	(785,836)
Cancelled during financial year	**–**	–
Cash-settled during financial year	**(363,452)**	(96,741)
Forfeited during financial year	**(1,291,847)**	(4,039,410)
Balance at end of financial year	**13,645,295**	14,861,486

Performance rights issued during the financial year were issued under the 2019 PRP.

The weighted average fair value of performance rights granted during the financial year was A$1.66 (2021: A$0.69). Fair values of STI performance rights were based on the Company's closing share price at grant date whereas LTI performance rights were based on a Monte Carlo simulation valuation at grant date. Refer to details at Note 31(d) below.

Performance rights outstanding as at 30 June 2022 had a weighted average remaining contractual life of 617 days (30 June 2021: 789 days). Details of performance rights outstanding at the end of the financial year are:

GRANT DATE	DATE OF EXPIRY	NUMBER
12 November 2019	30 June 2023	**685,621**
18 October 2019	30 June 2023	**2,367,643**
29 November 2019	30 June 2023	**666,323**
25 September 2020	30 June 2023	**2,880,420**
25 September 2020	30 June 2024	**4,172,267**
26 November 2021	30 June 2024	**502,989**
23 March 2022	30 June 2025	**1,123,593**
6 May 2022	30 June 2025	**1,246,439**
Total performance rights		**13,645,295**

(d) Fair Value of Performance Rights

The fair value of each LTI performance right issued during the financial year was estimated on grant date using the Monte Carlo valuation methodology. The Monte Carlo valuation methodology takes into account the exercise price, the term of the performance right, the share price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the performance right. The fair value of STI performance rights issued during the current or previous financial years were based on the Company's closing share price at grant date. The fair value of all performance rights issued prior to 1 July 2020 were based on the Company's closing share price at grant date.

The Group applied the following assumptions and inputs in estimating the weighted average fair value for LTI performance rights:

	2022	2021
Weighted average exercise price	**$A Nil**	$A Nil
Weighted average life of performance rights	**1,172 days**	1,383 days
Weighted average share price	**A$2.12**	A$0.80
Expected share price volatility	**60.00%**	60.00%
Risk free interest rate	**2.17%**	0.17%
Weighted average performance rights value	**A$1.66**	A$0.65

Historical volatility was the basis for determining expected share price volatility as it is assumed that this is indicative of future trends, which may not eventuate.

(e) Share-based Payments Expense

Total expenses arising from share-based payment transactions recognised during the financial year, included as part of other expenses in the consolidated statement of profit or loss and other comprehensive income, were as follows:

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Share options issued under ESOP	**–**	190
Performance rights issued under PRP	**3,632**	2,844
Share-based payments expense (non-cash)	**3,632**	3,034
Share-based payments expense (cash-settled)	**2,059**	1,872
Total share-based payments expense	**5,691**	4,906

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS CONTINUED

Note 32. Related Party Transactions

Transactions between related parties are on normal commercial terms and conditions, no more favourable than those available to other parties, unless otherwise stated.

(a) Subsidiaries

Interests in subsidiaries are set out in Note 25.

During the financial year, the Parent Company provided accounting, administrative and technical services to subsidiaries at cost or at cost plus a mark-up where required under relevant tax transfer pricing legislation. This allocation was based on costs recharged on a relevant time allocation of employees and consultants and associated office charges.

Other transactions that occurred were provision of funding by the Parent Company to its overseas subsidiaries via an increase in contributed equity and intercompany loans to the Australian subsidiaries. The intercompany loans provided are at a Nil% interest rate (2021: Nil%) and no fixed term for repayment and therefore will not be repaid within 12 months. Loans are unsecured and are repayable in cash.

Where equity-settled share options and performance rights are issued to employees of subsidiaries within the Group, the transaction is recognised as an investment in the subsidiary by the Parent Company and in the subsidiary, a share-based payments expense and an equity contribution by the Parent Company.

The above transactions are eliminated on consolidation.

(b) Remuneration of Key Management Personnel

Directors and other key management personnel remuneration is summarised as follows:

	CONSOLIDATED	
	2022 US$'000	2021 US$'000
Short-term employee benefits	**2,771**	2,390
Post-employment benefits	**221**	175
Long-term employee benefits (non-cash)	**4**	18
Termination benefits	**436**	470
Share-based payments expense	**2,307**	2,764
Total key management personnel remuneration	**5,739**	5,817

Detailed remuneration disclosures for the Directors and other key management personnel are provided in Section 5 of the audited Remuneration Report on pages 61 to 68. Termination of the Executive Director's and other key management personnel's employment is subject to a minimum notice period as disclosed on page 59 of the audited Remuneration Report.

Apart from the details disclosed in this note, no Director or other key management personnel has entered into a material contract with the Group since the end of the previous financial year and there were no material contracts involving Directors' or other key management personnel interests subsisting as at 30 June 2022.

Note 33. Parent Company Financial Information

(a) Summary Financial Information

The individual financial statements for the Parent Company show the following aggregate amounts:

	COMPANY 2022 US$'000	COMPANY 2021 US$'000
Statement of financial position		
Current assets	**47,625**	63,387
Non-current assets	**169,761**	253,939
Total assets	**217,386**	317,326
Current liabilities	**3,925**	3,234
Non-current liabilities	**920**	3,111
Total liabilities	**4,845**	6,345
Net assets	**212,541**	310,981
Contributed equity	**907,514**	905,138
Accumulated losses	**(653,433)**	(574,852)
Share-based payments reserve	**53,822**	50,190
Foreign currency translation reserve	**(95,362)**	(69,495)
Total equity	**212,541**	310,981
Loss for financial year	**(78,581)**	(16,982)
Total comprehensive loss for financial year	**(104,449)**	11,244

(b) Contingent Liabilities of Parent Company

(i) Bank guarantees were provided in respect of operating lease rental agreements. These guarantees may give rise to liabilities in the Parent Company if obligations are not met under these guarantees. The bank guarantees given to lessors are fully funded by way of payment of security deposits (refer Note 13).	**155**	169
(ii) The Company's present intention is to provide the necessary financial support for all Australian incorporated subsidiaries, whilst they remain wholly owned subsidiaries, as is necessary for each company to pay all debts as and when they become due.		

(c) Guarantees Entered into by Parent Company

A Parent Company guarantee was provided to Petrobras for payment of all amounts that may become payable under the SPA.

A Parent Company guarantee totalling Brazilian REALS 117.7 million (US$22.5 million equivalent as at 30 June 2022) was provided to the ANP in respect of existing decommissioning obligations relating to the Baúna field. In addition, the Parent has provided deeds of guarantee to, respectively, OOG-TKP FPSO GMBH & CO KG (the FPSO operator) and OOG-TKP Produção de Petróleo Ltda (the FPSO service provider) in relation to satisfying Karoon Petróleo & Gás Ltda's payment obligations in respect of the charter of an FPSO for Baúna and the provision of related services.

Parent Company guarantees have been provided to the ANP guaranteeing a subsidiary's obligations under Concession Agreements covering Santos Basin Blocks S-M-1037, S-M-1101, S-M-1102 and S-M-1537 in Brazil.

Note 34. Subsequent Events

This Annual Report was authorised for issue by the Board of Directors on 25 August 2022. The Board of Directors has the power to amend and reissue the consolidated financial statements and notes.

Since 30 June 2022, there have been no material events that have occurred.

DIRECTORS' DECLARATION

The Directors' declare that:

(a) in the Directors' opinion, the consolidated financial statements and notes, set out on pages 72 to 119, are in accordance with the *Corporations Act 2001*, including:

(i) complying with relevant Australian Accounting Standards and the Corporations Regulations 2001; and

(ii) giving a true and fair view of the Group's financial position as at 30 June 2022 and of its performance for the financial year ended on that date; and

(b) in the Directors' opinion, there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

Note 1(a) confirms that the consolidated financial statements also comply with International Financial Reporting Standards as issued by the International Accounting Standards Board.

The Directors have been given the declarations by the Chief Executive Officer and Managing Director, and Executive Vice President and Chief Financial Officer required by Section 295A of the *Corporations Act 2001*.

This Directors' Declaration is made in accordance with a resolution of the Directors.

On behalf of the Directors:

Mr Bruce Phillips
Independent Non-Executive Chairman

Dr Julian Fowles
Chief Executive Officer and Managing Director

25 August 2022

INDEPENDENT AUDITOR'S REPORT

Independent auditor's report

To the members of Karoon Energy Ltd

Report on the audit of the financial report

Our opinion

In our opinion:

The accompanying financial report of Karoon Energy Ltd (the Company) and its controlled entities (together the Group) is in accordance with the *Corporations Act 2001*, including:

(a) giving a true and fair view of the Group's financial position as at 30 June 2022 and of its financial performance for the year then ended, and

(b) complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

What we have audited

The Group financial report comprises:

- the consolidated statement of financial position as at 30 June 2022
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows for the year then ended
- the consolidated statement of profit or loss and other comprehensive income for the year then ended
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information, and
- the directors' declaration.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional & Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

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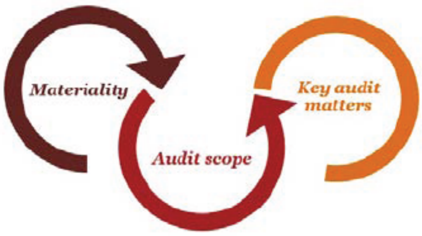
INDEPENDENT AUDITOR'S REPORT CONTINUED

Our audit approach

An audit is designed to provide reasonable assurance about whether the financial report is free from material misstatement. Misstatements may arise due to fraud or error. They are considered material if individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

We tailored the scope of our audit to ensure that we performed enough work to be able to give an opinion on the financial report as a whole, taking into account the geographic and management structure of the Group, its accounting processes and controls and the industry in which it operates.



Materiality

- For the purpose of our audit we used overall Group materiality of US$11.6 million, which represents approximately 1% of the Group's total assets.
- We applied this threshold, together with qualitative considerations, to determine the scope of our audit and the nature, timing and extent of our audit procedures and to evaluate the effect of misstatements on the financial report as a whole.
- We chose the Group's total assets as it is an appropriate benchmark that reflects the Group's interests in oil and gas assets.
- We utilised a 1% threshold based on our professional judgement, noting it is within the range of commonly acceptable thresholds.

Audit Scope

- Our audit focused on where the Group made subjective judgements; for example, significant accounting estimates involving assumptions and inherently uncertain future events.
- The Group has two operating segments in Australia and Brazil. In establishing the overall approach to the Group audit, we determined the type of work that needed to be performed by us, as the Group engagement team, and by component auditors under our instruction.

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Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report for the current period. The key audit matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. Further, any commentary on the outcomes of a particular audit procedure is made in that context. We communicated the key audit matters to the Audit and Risk Committee.

Key audit matter	How our audit addressed the key audit matter
Assessing the carrying value of oil and gas assets *(Refer to note 15)* As at 30 June 2022 the Group's consolidated statement of financial position includes oil and gas assets of US$733 million. Group policy is to assess for indicators of impairment annually or more frequently if indicators of impairment exist. Assessing the carrying value of oil and gas assets was a key audit matter because of the judgement involved in the Group assessing impairment indicators and the financial significance of oil and gas assets.	To assess the carrying value of oil and gas assets we performed the following procedures, amongst others: • Evaluated the Group's assessment of whether there were any indicators of asset impairment, including consideration of movement in oil prices, reserves and resources and asset performance over the period. • Compared the value of the net assets of the Group at year end to the market capitalisation.
Assessing the valuation of the contingent consideration payable *(Refer to note 23)* As described within Note 23, as part of the Group's acquisition of the Bauna production asset in the prior year, a tiered contingent consideration is payable of up to US$285 million (plus interest at 2% per annum). This contingent consideration was initially recognised as an embedded derivative and it is measured at fair valued at each reporting date. The fair value of the contingent consideration is determined by the Group's estimate of the present value of future expected cash outflows. Estimates are based on the Group's internal assessment of future oil prices, which considers industry consensus and observable oil price forecasts. The valuation of this liability was increased to US$298 million at 30 June 2022, an increase of US$227 million since 30 June 2021.	To assess the valuation of the contingent consideration we performed the following procedures, amongst others: • Evaluated the Group's accounting policy against the requirements of Australian Accounting Standards. • Assessed the appropriateness of methods, assumptions and inputs to the calculation of the fair value of contingent consideration. • We utilised an auditor's expert to assess the reasonableness of the Group's forecast of future oil prices.

INDEPENDENT AUDITOR'S REPORT CONTINUED

Key audit matter	How our audit addressed the key audit matter
Assessing the valuation of the contingent consideration payable was a key audit matter because of the judgement involved in the Group's forecast of future oil prices and the financial significance of this estimate on the Group's financial performance and financial position.	

Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report for the year ended 30 June 2022 but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and accordingly we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

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A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website at: https://www.auasb.gov.au/admin/file/content102/c3/ar1_2020.pdf. This description forms part of our auditor's report.

Report on the remuneration report

Our opinion on the remuneration report

We have audited the remuneration report included in pages 48 to 68 of the directors' report for the year ended 30 June 2022.

In our opinion, the remuneration report of Karoon Energy Ltd for the year ended 30 June 2022 complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the remuneration report in accordance with section 300A of *the Corporations Act 2001*. Our responsibility is to express an opinion on the remuneration report, based on our audit conducted in accordance with Australian Auditing Standards.

PricewaterhouseCoopers

PricewaterhouseCoopers

Anthony Hodge
Partner

Melbourne
25 August 2022

Building a better
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Report of Independent Auditors

To the Board of Directors of Karoon Energy Ltd.

Opinion

We have audited the Statements of Revenues and Direct Operating Expenses of the oil and natural gas properties acquired by Karoon Energy Ltd. (the "Company") on December 21, 2023 from LLOG Exploration Offshore, LLC and LLOG Omega Holdings, LLC (the "Acquired Assets") for each of the two years in the period ended December 31, 2023, and the related notes (the financial statements).

In our opinion, the accompanying financial statements present fairly, in all material respects, the revenues and direct operating expenses described in Note 1 of the Acquired Assets for each of the two years in the period ended December 31, 2023, in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Basis of Accounting

We draw attention to Note 1 to the financial statements, which describes that the accompanying financial statements were prepared for the purpose of inclusion in a privately negotiated bond offering of the Company and are not intended to be a complete presentation of the Acquired Assets' revenues and expenses. As a result, the financial statements may not be suitable for another purpose. Our opinion is not modified with respect to this matter.

Responsibilities of Management for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America, and for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of the financial statements that are free of material misstatement, whether due to fraud or error.

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Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free of material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the historical summaries.

- Obtain an understanding of internal control relevant procedures that are appropriate in the circumstances an opinion on the effectiveness of the Company's opinion is expressed.

- Evaluate the appropriateness of accounting policies significant accounting estimates made by management presentation of the financial statements.

- Conclude whether, in our judgment, there are conditions aggregate, that raise substantial doubt about the concern for a reasonable period of time.

We are required to communicate with those charged with governance matters, the planned scope and timing of the audit, significant control-related matters that we identified during the audit.

Ernst & Young LLP

April 5, 2024

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

	31 December 2023	31 December 2022
Revenues:		
Oil	$132,356,063	$153,482,728
Natural gas	16,147,000	46,446,268
Natural gas liquids	3,554,250	6,264,986
Total revenues	**152,057,313**	**206,193,982**
Lease operating expenses	21,930,843	19,868,292
Processing and transportation expenses	8,693,800	9,837,111
Direct operating expenses	**30,624,643**	**29,705,403**
Revenue less direct operating expenses	**$121,432,670**	**$176,488,579**

The accompanying notes are an integral part of the statements of revenues and direct operating expenses.

Note 1. Basis of Presentation

Karoon Energy Limited ("Karoon" or the "Company") successfully completed the acquisition of interests in the US Gulf of Mexico from LLOG Exploration Offshore, LLC and LLOG Omega Holdings (each of them a "Seller" and together, the "Sellers") on December 21, 2023. The acquisition comprises a 30% working interest in the Who Dat and Dome Patrol fields, including the associated infrastructure, an approximately 16% working interest in the Abilene field and varying interests in adjacent exploration acreage (together the "Acquired Assets"). The accompanying statements of revenues and direct operating expenses and cash investment in oil and gas properties relate to the operations of the Acquired Assets by Karoon.

The accompanying statements of revenues and direct operating expenses of the Acquired Assets were derived from the historical accounting records related to the Acquired Assets and represent the direct undivided interests in the revenues and direct operating expenses associated with the Acquired Assets during the periods presented. During the periods presented, the Acquired Assets were not accounted for or operated as a consolidated entity or as a separate division by the Sellers. Direct operating expenses include lease operating expenses and production and other related taxes. General and administrative expenses, depreciation, depletion and amortization of oil and gas properties and federal and state taxes have been excluded from direct operating expenses in the accompanying statements of revenues and direct operating expenses because the allocation of certain expenses would be arbitrary and would not be indicative of the costs which Karoon will incur upon the allocation of the purchase price paid for the Acquired Assets. Furthermore, no balance sheet has been presented for the Acquired Assets because the acquired properties were not accounted for as a separate subsidiary or division of the Sellers and complete financial statements are not available, nor has information about Acquired Assets operating and financing cash flows been provided for similar reasons. Full separate financial statements prepared in accordance with accounting principles generally accepted in the United States of America do not exist for the Acquired Assets and are not practicable to prepare in these circumstances. The statements of revenues and direct operating expenses presented may not be indicative of the financial condition or results of operations of the Acquired Assets on a go forward basis due to changes in the business and the omission of various operating expenses.

Note 2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of the statements of revenues and direct operating expenses in conformity with accounting principles generally accepted in the United States of America requires management to make certain estimates and assumptions that affect the reported amounts of revenues and expenses during the periods presented. Although these estimates are based on management's best available knowledge of current and future events, actual results could be different from those estimates.

Revenue Recognition

Revenues from the sale of crude oil, NGLs, and natural gas are recognized when the performance obligations are satisfied. Contracts with customers are primarily short-term (less than 12 months). The responsibility to deliver a unit of crude oil, NGL, and natural gas under these contracts represent separate, distinct performance obligations. These performance obligations are satisfied at the point in time control of each unit is transferred to the customer. Pricing is primarily determined utilizing a particular pricing or market index, plus or minus adjustments reflecting quality or location differentials.

Direct Operating Expenses

Direct operating expenses are recognized when incurred and consist of direct expenses of operating the Acquired Assets. The direct operating expenses include lease operating, processing and transportation expenses. Lease operating expenses include lifting costs, well repair expenses, facility maintenance expenses, well workover costs, and other field related expenses. Lease operating expenses also include expenses directly associated with support personnel, support services, equipment, and facilities directly related to oil and gas production activities.

Capital Expenditures

Capital expenditures related to the Acquired Assets for the years ended December 31, 2023 and 2022, were $58,206,588 and $7,645,762 respectively. These amounts include the costs to develop, acquire, construct, install or complete wells and any associated infrastructure facilities.

Note 3. Contingencies

The activities of the Acquired Assets may become subject to potential claims and litigation in the ordinary course of operations. The Company is not aware of any legal, environmental, or other claims or other contingencies that would have a material effect on the statements of revenue and direct operating expenses.

Note 4. Subsequent events

The Company has evaluated subsequent events through April 5, 2024, the date the statements of revenues and direct operating expenses were available to be issued and concluded that no events need to be reported.

Note 5. Supplementary Production and Operating Data (Unaudited)

The following volumetric, pricing and unit production cost data is derived from the abbreviated statements of profit or loss. This is presented for each of the 6-month periods from 1 January 2022 to 31 December 2023.

	31 December 23	30 June 23	31 December 22	30 June 22
Production Volume				
Oil (bbl)	928,749	813,657	810,000	830,174
Natural Gas (mcf)	3,149,529	3,070,634	3,626,812	3,519,822
Natural Gas Liquids (gal)	-	-	-	-
Total Production (boe)	**1,453,671**	**1,325,430**	**1,414,468**	**1,416,811**
Sales Volume				
Oil (bbl)	900,002	799,589	797,630	830,712
Natural Gas (mcf)	2,781,969	2,687,526	3,193,755	3,120,282
Natural Gas Liquids (gal)	2,462,747	2,438,278	2,711,798	3,261,796
Total Sales (boe)	**1,422,277**	**1,305,541**	**1,394,463**	**1,428,390**
Net Realized Price				
Oil ($/bbl)	$81.77	$73.50	$86.68	$101.53
Natural Gas ($/mcf)	$3.17	$2.72	$8.46	$6.23
Natural Gas Liquids ($/gal)	$0.71	$0.74	$0.97	$1.11
Weighted average realized price ($/boe)	**$59.19**	**$51.99**	**$70.85**	**$75.19**
Unit Direct operating expenses:				
Direct operating expenses ($ per boe)	**$11.80**	**$10.60**	**$10.26**	**$10.78**

KAROON USA FINANCE INC

US$350,000,000
10.500% Second-Priority Senior Secured Notes due 2029

OFFERING MEMORANDUM

May 7, 2024

Sole Global Coordinator and Joint Physical Bookrunner
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Joint Physical Bookrunner
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