ANNUAL REPORT 2022

GeoPark ANNUAL REPORT 2022

EXPLORER OPERATOR CONSOLIDATOR

GEOPARK

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 20-F

(Mark One)

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2022

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ______________________ to ___________________________

OR

☐ **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
Date of event requiring this shell company report

Commission file number: 001-36298

GEOPARK LIMITED

(Exact name of Registrant as specified in its charter)

Bermuda
(Jurisdiction of incorporation)

Calle 94 N° 11-30, 8º floor
Bogotá, Colombia
(Address of principal executive offices)
Mónica Jiménez González
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GeoPark Limited
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Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbols	Name of each exchange on which registered
Common shares, par value US$0.001 per share	GPRK	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:
None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None

Indicate the number of outstanding shares of each of the issuer's classes of capital stock or common stock as of the close of business covered by the annual report.

Common shares: 57,621,998

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☐ No ☒

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically, every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or an emerging growth company. See definition of "large accelerated filer", "accelerated filer", and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

US GAAP ☐ International Financial Reporting Standards as issued by the International Accounting Standards Board ☒ Other ☐

If "Other" has been checked in response to the previous question indicate by check mark which financial statement item the registrant has elected to follow.

☐ Item 17 ☐ Item 18

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

GEOPARK LIMITED

TABLE OF CONTENTS

GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms defined in this section are used throughout this annual report:

"appraisal well" means a well drilled to further confirm and evaluate the presence of hydrocarbons in a reservoir that has been discovered.

"API" means the American Petroleum Institute's inverted scale for denoting the "light" or "heaviness" of crude oils and other liquid hydrocarbons.

"bbl" means one stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"bcf" means one billion cubic feet of natural gas.

"bcm" means billion cubic meters.

"boe" means barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

"boepd" means barrels of oil equivalent per day.

"bopd" means barrels of oil per day.

"British thermal unit" or "btu" means the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"basin" means a large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"CEOP" (*Contrato Especial de Operación*) means a special operating contract the Chilean signs with a company or a consortium of companies for the exploration and exploitation of hydrocarbon wells.

"completion" means the process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"developed acreage" means the number of acres that are allocated or assignable to productive wells or wells capable of production.

"developed reserves" are 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.

"development well" means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"dry hole" means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"E&P contract" means exploration and production contract.

"economic interest" means an indirect participation interest in the net revenues from a given block based on bilateral agreements with the concessionaires.

“economically producible” means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

“exploratory well” means a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well as those items are defined below.

“field” means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

“formation” means a layer of rock which has distinct characteristics that differ from nearby rock.

“mbbl” means one thousand barrels of crude oil, condensate, or natural gas liquids.

“mboe” means one thousand barrels of oil equivalent.

“mcf” means one thousand cubic feet of natural gas.

“Measurements” include:

- “m” or “meter” means one meter, which equals approximately 3.28084 feet;
- “km” means one kilometer, which equals approximately 0.621371 miles;
- “sq. km” means one square kilometer, which equals approximately 247.1 acres;
- “bbl” “bo,” or “barrel of oil” means one stock tank barrel, which is equivalent to approximately 0.15898 cubic meters;
- “boe” means one barrel of oil equivalent, which equals approximately 160.2167 cubic meters, determined using the ratio of 6,000 cubic feet of natural gas to one barrel of oil;
- “cf” means one cubic foot;
- “m,” when used before bbl, boe or cf, means one thousand bbl, boe or cf, respectively;
- “mm,” when used before bbl, boe or cf, means one million bbl, boe or cf, respectively;
- “b,” when used before bbl, boe or cf, means one billion bbl, boe or cf, respectively; and
- “pd” means per day.

“metric ton” or “MT” means one thousand kilograms. Assuming standard quality oil, one metric ton equals 7.9 bbl.

“mmbbl” means one million barrels of crude oil, condensate or natural gas liquids.

“mmboe” means one million barrels of oil equivalent.

“mmbtu” means one million British thermal units.

“productive well” means a well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

“prospect” means a potential trap which may contain hydrocarbons and is supported by the necessary amount and quality of geologic and geophysical data to indicate a probability of oil and/or natural gas accumulation ready to be drilled. The five required elements (generation, migration, reservoir, seal and trap) must be present for a prospect to work and if any of them fail neither oil nor natural gas will be present, at least not in commercial volumes.

“proved developed reserves” means those proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

“proved reserves” means estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4 10(a)(2).

“proved undeveloped reserves” means are those proved reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in reservoirs which have previously shown favorable response to improved recovery projects.

“reasonable certainty” means a high degree of confidence.

“recompletion” means the process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

“reserves” means estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, a revenue interest in the production, installed means of delivering oil, gas, or related substances to market, and all permits and financing required to implement the project.

“reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“royalty” means a fractional undivided interest in the production of oil and natural gas wells or the proceeds therefrom, to be received free and clear of all costs of development, operations or maintenance.

“service well” means a well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation, or injection for in-situ combustion.

“shale” means a fine-grained sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers. Shale can include relatively large amounts of organic material compared with other rock types and thus has the potential to become rich hydrocarbon source rock. Its fine grain size and lack of permeability can allow shale to form a good cap rock for hydrocarbon traps.

“spacing” means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (*e.g.*, 40-acre spacing, and is often established by regulatory agencies).

“stratigraphic test well” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) exploratory-type, if not drilled in a proved area, or (ii) development-type, if drilled in a proved area.

"undeveloped reserves" are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulation, (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.

"unit" means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"wellbore" means the hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

"working interest" means the right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"workover" means operations in a producing well to restore or increase production.

PRESENTATION OF FINANCIAL AND OTHER INFORMATION

Certain definitions

Unless otherwise indicated or the context otherwise requires, all references in this annual report to:

- "GeoPark Limited," "GeoPark," "we," "us," "our," the "Company" and words of a similar effect, are to GeoPark Limited, an exempted company incorporated under the laws of Bermuda, together with its consolidated subsidiaries;
- "Amerisur" are to Amerisur Resources Limited and its subsidiaries;
- "GeoPark Brazil" are to GeoPark Brasil Exploração e Produção de Petróleo e Gás Ltda.;
- "Petroperu" are to Petróleos del Perú S.A.;
- "YPF" are to YPF S.A.;
- "ONGC" are to ONGC Videsh Limited, international petroleum company of India;
- "Petroamazonas" are to Petroamazonas Ecuador S.A.;
- "Petroecuador" are to Empresa Pública de hidrocarburos del Ecuador;
- "MSCI" are to Morgan Stanley Capital International;
- "Notes due 2024" are to our 2017 issuance of US$425.0 million aggregate principal amount of 6.50% senior notes due 2024;
- "Notes due 2027" are to our 2020 issuance of US$350.0 million aggregate principal amount of 5.50% senior notes due 2027;
- "Banco Santander Loan" are to our loan agreement with Banco Santander from October 2018, for Brazilian *reais* 77.6 million (equivalent to US$20 million at the moment of the loan execution) to repay an existing intercompany loan, which outstanding amount of Brazilian reais 19.4 million (equivalent to US$3.4 million at the moment of the refinancing execution) was refinanced with the bank in September 2020, and was paid in three equal installments in October 2021, April 2022, and October 2022;
- "US$" and "U.S. dollar" are to the official currency of the United States of America;
- "Ch$" and "Chilean pesos" are to the official currency of Chile;
- "AR$" and "Argentine pesos" are to the official currency of Argentina;
- "*real*," "*reais*" and "R$" are to the official currency of Brazil;
- "ANP" are to the Brazilian National Petroleum, Natural Gas and Biofuels Agency (*Agência Nacional do Petróleo, Gás Natural e Biocombustíveis*);
- "ANH" are to the Colombian National Hydrocarbons Agency (*Agencia Nacional de Hidrocarburos*);
- "ENAP" are to the Chilean National Petroleum Company (*Empresa Nacional de Petróleo*);

- “RODA” are to the Oil Pipeline Network of the Amazonian District (*Red de Oleoductos del Distrito Amazónico*);
- “SOTE” are to the Ecuadorian Oil Pipeline System (*Sistema de Oleoducto Transecuatoriano*);
- “IOGP” are to the International Association of Oil and Gas Producers;
- “IPIECA” are to the International Petroleum Industry Environmental Conservation Association;
- “IADC” are to the International Association of Drilling Contractors;
- “ARPEL” are to the Regional Association of Oil and Gas Companies, a non-profit association gathering oil, gas and biofuels sector companies and institutions in Latin America and the Caribbean;
- “UTA” are to *Unidad Tributaria Anual*;
- “economic interest” are to an indirect participation interest in the net revenues from a given block based on bilateral agreements with the concessionaires;
- “ESG” are to Environmental, Social and Governance; and
- “IFC” are to International Finance Corporation.

Financial statements

Our historical financial data presented does not include any results or other financial information of any acquisitions, including the acquisition of Amerisur, prior to their incorporation into our financial statements.

Our consolidated financial statements

This annual report includes our audited consolidated financial statements as of December 31, 2022 and 2021 and for each of the years ended December 31, 2022, 2021 and 2020 (hereinafter “Consolidated Financial Statements”).

Our Consolidated Financial Statements are presented in US$ and have been prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board (“IASB”).

Our Consolidated Financial Statements for the year ended December 31, 2022, have been audited by Pistrelli, Henry Martin y Asociados S.R.L., (member of Ernst & Young Global Limited), an independent registered public accounting firm, as stated in their reports included elsewhere in this annual report.

Our fiscal year ends December 31. References in this annual report to a fiscal year, such as “fiscal year 2022,” relate to our fiscal year ended on December 31 of that calendar year.

Non IFRS financial measures

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-IFRS financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies, to assess the performance of our Company and the operating segments.

We define Adjusted EBITDA as profit (loss) for the period (determined as if IFRS 16 Leases has not been adopted), before net finance cost, income tax, depreciation, amortization, certain non-cash items such as impairments and write-offs of unsuccessful exploration efforts, accrual of share-based payment, unrealized result on commodity risk management contracts, geological and geophysical expenses allocated to capitalized projects, and other non-recurring events. Adjusted EBITDA is not a measure of profit or cash flows as determined by IFRS.

We believe Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from profit (loss) for the period in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, profit (loss) for the period or cash flows from operating activities as determined in accordance with IFRS or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure and significant and/or recurring write-offs, as well as the historic costs of depreciable assets, or unrealized results in commodity risk management contracts, none of which are components of Adjusted EBITDA. Our computation of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

For a reconciliation of Adjusted EBITDA to the IFRS financial measure of profit for the year, see Note 6 to our Consolidated Financial Statements as of and for the years ended 2022, 2021 and 2020.

Oil and gas reserves and production information

DeGolyer and MacNaughton 2022 Year-end Reserves Report

The information included elsewhere in this annual report regarding estimated quantities of proved reserves in Colombia, Chile, Brazil and Ecuador is derived from estimates of the proved reserves as of December 31, 2022. The reserves estimates described herein are derived from the DeGolyer and MacNaughton Reserves Report ("D&M Reserves Report"), which was prepared for us by the independent reserves engineering team of DeGolyer and MacNaughton Corp. and is included as an exhibit to this annual report. The D&M Reserves Report presents oil and gas reserves estimates located in the Llanos 32, Llanos 34, Platanillo and CPO-5 Blocks in Colombia, the Fell Block in Chile, the BCAM-40 (Manati) Block in Brazil and the Espejo and Perico Blocks in Ecuador.

Market share and other information

Market data, other statistical information, information regarding recent developments in Colombia, Chile, Brazil, Argentina and Ecuador and certain industry forecast data used in this annual report were obtained from internal reports and studies, where appropriate, as well as estimates, market research, publicly available information and industry publications. Industry publications generally state that the information they include has been obtained from sources believed to be reliable, but that the accuracy and completeness of such information is not guaranteed. Similarly, internal reports and studies, estimates and market research, which we believe to be reliable and accurately extracted by us for use in this annual report, have not been independently verified. However, we believe such data is accurate and agree that we are responsible for the accurate extraction of such information from such sources and its correct reproduction in this annual report.

In addition, we have provided definitions for certain industry terms used in this annual report in the "Glossary of oil and natural gas terms".

Rounding

We have made rounding adjustments to some of the figures included elsewhere in this annual report. Accordingly, numerical figures shown as totals in some tables may not be an arithmetic aggregation of the figures that precede them.

FORWARD-LOOKING STATEMENTS

This annual report contains statements that constitute forward-looking statements. Many of the forward-looking statements contained in this annual report can be identified by the use of forward-looking words such as "anticipate," "believe," "could," "expect," "should," "plan," "intend," "will," "estimate" and "potential," among others.

Forward-looking statements appear in a number of places in this annual report and include, but are not limited to, statements regarding our intent, belief or current expectations. Forward-looking statements are based on our management's beliefs and assumptions and on information currently available to our management. Such statements are subject to risks and uncertainties, and actual results may differ materially from those expressed or implied in the forward-looking statements due to various factors, including, but not limited to, those identified under the section "Item 3. Key Information—D. Risk factors" in this annual report. These risks and uncertainties include factors relating to:

- pandemics, or the future outbreak of any other highly infectious or contagious disease, including the COVID-19 pandemic;
- the volatility of oil and natural gas prices;
- operating risks, including equipment failures and the amounts and timing of revenues and expenses;
- termination of, or intervention in, concessions, rights or authorizations granted by the Colombian, Chilean, Brazilian and Ecuadorian governments to us;
- uncertainties inherent in making estimates of our oil and natural gas data;
- environmental constraints on operations and environmental liabilities arising out of past or present operations;
- discovery and development of oil and natural gas reserves;
- climate change related risks;
- project delays or cancellations;
- financial market conditions and the results of financing efforts;
- political, legal, regulatory, governmental, administrative and economic conditions and developments in the countries in which we operate;
- the recent social and political unrest, driven in many cases by populist groups, in many countries in which we operate;
- fluctuations in inflation and exchange rates in Colombia, Chile, Brazil, Ecuador and in other countries in which we may operate in the future;
- availability and cost of drilling rigs, production equipment, supplies, personnel and oil field services;
- contract counterparty risk;
- projected and targeted capital expenditures and other cost commitments and revenues;
- weather and other natural phenomena;

- armed conflicts, including the current armed conflict in Ukraine;
- the impact of recent and future regulatory proceedings and changes, changes in environmental, health and safety and other laws and regulations to which our company or operations are subject, as well as changes in the application of existing laws and regulations;
- current and future litigation;
- our ability to successfully identify, integrate and complete pending or future acquisitions and dispositions;
- our ability to retain key members of our senior management and key technical employees;
- competition from other similar oil and natural gas companies;
- market or business conditions and fluctuations in global and local demand for energy;
- the direct or indirect impact on our business resulting from terrorist incidents or responses to such incidents, including the effect on the availability of and premiums on insurance;
- the adverse effect which a substantial or extended decline in oil, natural gas and methanol price may have on our business;
- the difficulty in integrating significant acquisitions or unexpected contingencies or changes in reserves estimates we discover following the completion of such acquisitions; and
- other factors discussed under "Item 3. Key Information—D. Risk factors" in this annual report.

Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them in light of new information or future developments or to release publicly any revisions to these statements in order to reflect later events or circumstances or to reflect the occurrence of unanticipated events.

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PART I

ITEM 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

A. Directors and senior management

Not applicable.

B. Advisers

Not applicable.

C. Auditors

Not applicable.

ITEM 2. OFFER STATISTICS AND EXPECTED TIMETABLE

A. Offer statistics

Not applicable.

B. Method and expected timetable

Not applicable.

ITEM 3. KEY INFORMATION

A. Reserved

B. Capitalization and indebtedness

Not applicable.

C. Reasons for the offer and use of proceeds

Not applicable.

D. Risk factors

Our business, financial condition and results of operations could be materially and adversely affected if any of the risks described below occur. As a result, the market price of our common shares could decline, and you could lose all or part of your investment. This annual report also contains forward-looking statements that involve risks and uncertainties. See "Forward-Looking Statements." The risks below are not the only ones facing our Company. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. The following risk factors have been grouped as follows:

a) Risks relating to our business;

b) Risks relating to the countries in which we operate; and

c) Risks relating to our common shares.

Summary of Key Risks

Our business is subject to numerous risks and uncertainties, discussed in more detail below. These risks include, among others, the following key risks:

- The COVID-19 pandemic has and may continue to adversely impact our business, financial condition, and results of our operations, the global economy, and the demand for and prices of oil and natural gas. The uncertainty of the impact an endemic or pandemic disease may have makes it impossible for us to identify all potential risks related to the pandemic or estimate the ultimate adverse impact that the pandemic may have on our business.
- A substantial or extended decline in oil, natural gas and methanol prices may materially adversely affect our business, financial condition, or results of operations.
- Low oil prices may impact our operations and corporate strategy.
- Unless we replace our oil and natural gas reserves, our reserves and production will decline over time. Our business is dependent on our continued successful identification of productive fields and prospects and the identified locations in which we drill in the future may not yield oil or natural gas in commercial quantities.
- We derive a significant portion of our revenues from sales to a few key customers.
- Our results of operations could be materially adversely affected by fluctuations in foreign currency exchange rates.
- There are inherent risks and uncertainties relating to the exploration and production of oil and natural gas.
- Our identified potential drilling location inventories are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- Our business requires significant capital investment and maintenance expenses, which we may be unable to finance on satisfactory terms or at all.
- Oil and gas operations contain a high degree of risk, and we may not be fully insured against all risks we face in our business.
- The development schedule of oil and natural gas projects is subject to cost overruns and delays.
- Competition in the oil and natural gas industry is intense, which makes it difficult for us to attract capital, acquire properties and prospects, market oil and natural gas and secure trained personnel.
- Our estimated oil and gas reserves are based on assumptions that may prove inaccurate.
- Our inability to access needed equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets and generate significant incremental costs or delays in our oil and natural gas production.
- We may suffer delays or incremental costs due to difficulties in negotiations with landowners and local communities, including indigenous communities, where our reserves are located.
- Under the terms of some of our various CEOPs, E&P contracts, production sharing agreements and concession agreements, we are obligated to drill wells, declare any discoveries, and file periodic reports to retain our rights and establish development areas. Failure to meet these obligations may result in the loss of our interests in the undeveloped parts of our blocks or concession areas.
- Our contracts in obtaining rights to explore and develop oil and natural gas reserves are subject to contractual expiration dates and operating conditions, and our CEOPs, E&P contracts, production sharing agreements and concession agreements are subject to early termination in certain circumstances.

- We sell all our natural gas in Chile to a single customer, who has in the past temporarily idled its principal facility.
- We are not, and may not be in the future, the sole owner or operator of all our licensed areas and do not, and may not in the future, hold all the working interests in some of our licensed areas. Therefore, we may not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and, to an extent, any non-wholly owned, assets.
- Acquisitions that we have completed, and any future acquisitions, strategic investments, partnerships, or alliances could be difficult to integrate and/or identify, could divert the attention of key management personnel, disrupt our business, dilute stockholder value and adversely affect our financial results, including impairment of goodwill and other intangible assets.
- The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.
- The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our proved undeveloped reserves ultimately may not be developed or produced.
- We are exposed to the credit risks of our customers and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.
- Our operations are subject to operating hazards, including extreme weather events, which could expose us to potentially significant losses.
- We are highly dependent on certain members of our management and technical team, including our geologists and geophysicists, and on our ability to hire and retain new qualified personnel.
- We and our operations are subject to numerous environmental, social, health and safety laws, regulations and rulings, which may result in material liabilities and costs.
- Changing investor sentiment towards fossil fuels may affect our operations, impact the price of our common shares and limit our access to financing and insurance.
- Legislation and regulatory initiatives relating to hydraulic fracturing and other drilling activities for unconventional oil and gas resources could increase the future costs of doing business, cause delays or impede our plans, and materially adversely affect our operations.
- Our indebtedness and other commercial obligations could adversely affect our financial health and our ability to raise additional capital and prevent us from fulfilling our obligations under our existing agreements and borrowing of additional funds.
- Our business could be negatively impacted by security threats, including cybersecurity threats as well as other disasters, and related disruptions.
- We operate in an industry with climate related risks.
- We operate in areas of significant biodiversity value.
- We operate in areas that have historical and current ties to indigenous peoples.
- Exploration blocks in the Putumayo area carry significant costs related to biodiversity management and reputational risk due to overlapping claims of rightful ownership.
- Our operations may be adversely affected by political and economic circumstances in the countries in which we operate and in which we may operate in the future.

- We depend on maintaining good relations with the respective host governments and national oil companies in each of our countries of operation.

- Oil and natural gas companies in Colombia, Chile, Brazil and Ecuador do not own any of the oil and natural gas reserves in such countries.

- Oil and gas operators are subject to extensive regulation in the countries in which we operate.

- Colombia has experienced and continues to experience internal security issues that have had or could have a negative effect on the Colombian economy.

- Our operations in Colombia are subject to security and human rights risks.

- We expect that a limited number of financial institutions in the countries in which we operate, as well as some institutions located in the United States, will hold all or most of our cash.

- An active, liquid, and orderly trading market for our common shares may not develop and the price of our stock may be volatile, which could limit your ability to sell our common shares.

- Any decision to pay dividends in the future, and the amount of any distributions, is at the discretion of our board of directors, and will depend on many factors, such as our results of operations, financial condition, cash requirements, prospects and other factors.

- We are a holding company and our only material assets are our equity interests in our operating subsidiaries and our other investments; as a result, our principal source of revenue and cash flow is distributions from our subsidiaries; our subsidiaries may be limited by law and by contract in making distributions to us.

- Sales of substantial amounts of our common shares in the public market, or the perception that these sales may occur, could cause the market price of our common shares to decline.

- Provisions of the Notes due 2027 could discourage an acquisition of us by a third party.

- Certain shareholders have substantial influence over us and could limit your ability to influence the outcome of key transactions, including a change of control.

- Shareholder activism could cause us to incur significant expenses, hinder execution of our business strategy and impact our stock price.

- As a foreign private issuer, we are subject to different U.S. securities laws and NYSE governance standards than domestic U.S. issuers. This may afford less protection to holders of our common shares, and you may not receive corporate and company information and disclosure that you are accustomed to receiving or in a manner in which you are accustomed to receiving it.

- There are regulatory limitations on the ownership and transfer of our common shares which could result in the delay or denial of any transfers you might seek to make.

- We are a Bermuda company, and it may be difficult for you to enforce judgments against us or against our directors and executive officers.

- The transfer of our common shares may be subject to capital gains taxes pursuant to indirect transfer rules in Colombia.

- Legislation enacted in Bermuda as to Economic Substance may affect our operations.

Risks relating to our business

The COVID-19 pandemic has and may continue to adversely impact our business, financial condition, and results of our operations, the global economy, and the demand for and prices of oil and natural gas. The uncertainty of the impact an endemic or pandemic disease may have makes it impossible for us to identify all potential risks related to the pandemic or estimate the ultimate adverse impact that the pandemic may have on our business.

The COVID-19 pandemic and the actions taken by third parties, including, but not limited to, governmental authorities, businesses, and consumers, in response to the pandemic adversely impacted the global economy and created significant volatility in the global financial markets. The COVID-19 pandemic resulted in significant volatility in the financial and commodities markets worldwide, including the dramatic drop in the price of crude oil during 2020. In the event of a potential resurgence of the COVID-19 pandemic, responsive measures may be implemented and further disruptions to the global economy, demand, supply chain and others may occur.

As of the date of this annual report, we believe we have implemented adequate operational measures (such as remote working procedures) to avoid or minimize major disruptions to our business. However, our operations rely on our workforce being able to access our wells, structures and facilities located upon or used in connection with our oil and gas blocks. The uncertainty of the impact that an endemic or pandemic disease may have makes it impossible for us to identify all potential risks related to the COVID-19 pandemic and we cannot assure if, and to what extent, our business, financial condition, cash flows or results of operations may be adversely impacted by any potential resurgence or outbreak of the COVID-19 pandemic, or any other regional or global outbreaks related to any other endemic or pandemic disease.

The COVID-19 pandemic and its unprecedented consequences amplified, and may continue to amplify, the other risks identified in this annual report.

A substantial or extended decline in oil, natural gas and methanol prices may materially adversely affect our business, financial condition, or results of operations.

The prices that we receive for our oil and natural gas production heavily influence our revenues, profitability, access to capital and growth rate. Historically, the markets for oil, natural gas, and methanol (which influence the price for our Chilean gas sales) have been volatile and will likely continue to be volatile in the future. International oil, natural gas and methanol prices have fluctuated widely in recent years and may continue to do so in the future.

The prices that we will receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited, to the following:

- global economic conditions;
- changes in global supply and demand for oil, natural gas and methanol;
- the conflict in Ukraine and other armed conflicts;
- the actions of the Organization of the Petroleum Exporting Countries (“OPEC”);
- political and economic conditions, including embargoes, in oil-producing countries or affecting other countries;
- the level of oil- and natural gas-producing activities, particularly in the Middle East, Africa, Russia, South America and the United States;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;

- the price of methanol;
- availability of markets for natural gas;
- weather conditions and other natural disasters;
- technological advances affecting energy production or consumption;
- domestic and foreign governmental laws and regulations, including environmental, health and safety laws and regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas;
- quality discounts for oil production based, among other things, on API, sulphur and mercury content;
- taxes and royalties under relevant laws and the terms of our contracts;
- our ability to enter into oil and natural gas sales contracts at fixed prices;
- the level of global methanol demand and inventories and changes in the uses of methanol;
- the price and availability of alternative fuels, and possible regulations establishing costs for carbon emissions along the value chain; and
- future changes to our hedging policies.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and methanol price movements. For example, during the three-year period from March 1, 2020, to February 28, 2023, Brent spot prices ranged from a low of US$19.3 per barrel to a high of US$128.0 per barrel. Furthermore, oil, natural gas and methanol prices do not necessarily fluctuate in direct relationship to each other.

Starting in March 2020, the oil market experienced a significant over-supply condition that resulted in a sharp drop in prices, with Brent falling from over US$50 per barrel at the beginning of March 2020, up to under US$20 per barrel in late April 2020. There were two key drivers for this market scenario:

- On the demand side, the sustained impact of the COVID-19 pandemic across the world and the associated containment measures, resulted in a sharp and sudden drop in fuel demand and hence on crude demand as well. This impact had been felt since early 2020 but accelerated significantly in March and April.
- Concurrently, on the supply side, during the first week of March 2020, OPEC and non-OPEC producers (sometimes referred to as OPEC+) met to discuss the prospect of extending or increasing oil production cuts that had been first put in place in late 2016 and had been renewed and expanded ever since. No consensus was reached among the 24 participating countries, effectively eliminating output reduction targets as of April 1, 2020. As a consequence, OPEC+ countries and especially Saudi Arabia, significantly increased production during April 2020.

The combined impact of sharply lower demand and growing supply led the market into a significant oil surplus with inventories building around the world and prices dropping to levels last seen in the early 2000s.

In mid-April, in the midst of a significant demand reduction, OPEC+ agreed to a historical 9.7 MMbbl/d output cut. They were joined by other G-20 countries, which indicated they would reduce their production between 3 and 5 MMbbl/d.

The crude oil market continued normalizing during early 2021 and shifted into an undersupply condition towards the end of the year. This condition was mainly driven by continued demand recovery while supply grew at a slower pace. OPEC+ paced output increase and capital discipline elsewhere, especially within the US Shale producers, were the key factors for moderate supply growth. In addition, natural gas prices spiked significantly during the last quarter of 2021, especially in Europe, pushing oil prices higher as well. These factors brought Brent prices up to US$78 per barrel at the end of 2021.

The armed conflict between Russia and Ukraine during 2022, and the imposition of comprehensive sanctions against Russia (including in relation to the Russian energy sector), as well as the announcement of prohibitions on Russian oil and gas imports by certain members of the European Union, the United Kingdom, the United States, and other countries, has led to volatility in the price of global oil and gas. For example, Brent spot price rose to a maximum of US$128 per barrel in March 2022.

By the second half of 2022, sharply rising inflation has led central banks to shift to a more restrictive policy stance, which historically is indicative of a potential economic recession. An economic recession could influence crude oil demand and, therefore, lead to a drop in crude oil prices, which dropped to US$86 per barrel by the end of 2022, 30% lower from the levels observed in June 2022. The oil embargo on Russia, the OPEC+ preemptive cuts in production and expectations of rising Chinese demand have managed to stabilize prices, but the risks of further declines continue to rise, especially as it is difficult to predict the magnitude of the impact that a potential economic recession would have.

For the year ended December 31, 2022, 97% of our revenues were derived from oil. Because we expect that our production mix will continue to be weighted towards oil, our financial results are more sensitive to movements in oil prices.

For the year ended December 31, 2022, natural gas comprised 3% of our revenues. A decline in natural gas prices could negatively affect our future growth, particularly for future gas sales where we may not be able to secure or extend our current long-term contracts.

Lower oil and natural gas prices may impact our revenues on a per unit basis and may also reduce the amount of oil and natural gas that can be produced economically. In addition, changes in oil and natural gas prices can impact the valuation of our reserves and, in periods of lower commodity prices, we may curtail production and capital spending or may defer or delay drilling wells because of lower cash generation. Lower oil and natural gas prices could also affect our growth, including future and pending acquisitions. A substantial or extended decline in oil or natural gas prices could adversely affect our business, financial condition, and results of operations.

Continuing our hedging strategy, we entered into derivative financial instruments to manage exposure to oil price risk. These derivatives were zero-premium collars and were placed with major financial institutions and commodity traders. We entered into the derivatives under ISDA Master Agreements and Credit Support Annexes.

To the extent that we engage in oil price risk management activities to protect ourselves from declines in oil price, we may be prevented from realizing the benefits of oil price increases above the levels of the zero-premium collars used to manage oil price risk.

As market values of these derivatives fluctuate, we may post or receive variation cash collaterals with our counterparties. In the event of a significant decrease in the market value of the derivatives, we may have to post cash collateral, if they exceed our available credit lines. Even though cash collateral is returned to us upon reductions in the underlying Brent oil price, having to post cash collaterals could affect our near-term liquidity needs. As of the date of this annual report, we have no cash collateral posted related to our commodity risk management contracts. See Note 8 to our Consolidated Financial Statements for details regarding Commodity Risk Management Contracts.

Low oil prices may impact our operations and corporate strategy.

We face limitations on our ability to increase prices or improve margins on the oil and natural gas that we sell. As a consequence of the oil price crisis which started in the first half of 2020 (WTI and Brent, the main international oil price markers, fell by more than 45% between December 2019 and March 2020), we immediately took decisive measures to ensure our ability to both maximize ongoing projects and to preserve our cash, such as reducing our work program and made adjustments to our operating and administrative costs, with continuous monitoring to adjust further if necessary. While oil prices have rebounded in 2021 and 2022, oil prices may continue to be volatile and thus, we develop multiple scenarios for our capital expenditure plan. See "Item 4. Information on the Company—B. Business Overview—2023 Strategy and Outlook".

Funding our anticipated capital expenditures relies in part on oil prices remaining close to our estimates or higher levels and other factors to generate sufficient cash flow. Low oil prices affect our revenues, which in turn affect our debt capacity and the covenants in our financing agreements, as well as the amount of cash we can borrow using our oil reserves as collateral, the amount of cash we are able to generate from current operations and the amount of cash we can obtain from prepayment agreements. If we are not able to generate the sales which, together with our current cash resources, are sufficient to fund our capital program, we will not be able to efficiently execute our work program, which would cause us to further decrease our work program and would harm our business outlook, investor confidence and our share price.

In addition, actions taken by the company to maximize ongoing projects and to reduce expenses, including renegotiations and reduction of oil and gas service contracts and other initiatives such as cost cutting may expose us to claims and contingencies from interested parties that may have a negative impact on our business, financial condition, results of operations and cash flows. If oil prices are lower than expected, we may be unable to meet our contractual obligations with oil and service contracts and suppliers. Equally, those third parties may be unable to meet their contractual obligations to us as a result of the oil price crisis, impacting on our operations.

In budgeting for our future activities, we have relied on a number of assumptions, including, with regard to our discovery success rate, the number of wells we plan to drill, our working interests in our prospects, the costs involved in developing or participating in the development of a prospect, the timing of third-party projects and our ability to obtain needed financing with respect to any further acquisitions and the availability of both suitable equipment and qualified personnel. These assumptions are inherently subject to significant business, political, economic, regulatory, environmental, and competitive uncertainties, conditions in the financial markets, contingencies, and risks, all of which are difficult to predict and many of which are beyond our control. In addition, we opportunistically seek out new assets and acquisition targets to complement our existing operations and have financed such acquisitions in the past through the incurrence of additional indebtedness, including additional bank credit facilities, equity issuances or the sale of minority stakes in certain operations to our partners. We may need to raise additional funds more quickly if one or more of our assumptions prove to be incorrect or if we choose to expand our hydrocarbon asset acquisition, exploration, appraisal or development efforts more rapidly than we presently anticipate, and we may decide to raise additional funds even before we need them if the conditions for raising capital are favorable. The ultimate amount of capital that we will expend may fluctuate materially based on market conditions, our continued production, decisions by the operators in blocks we do not operate, the success of our drilling results and future acquisitions. Our future financial condition and liquidity will be impacted by, among other factors, our level of production of oil and natural gas and the prices we receive from the sale thereof, the success of our exploration and appraisal drilling program, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production and the actual cost of exploration, appraisal and development of our oil and natural gas assets.

Unless we replace our oil and natural gas reserves, our reserves and production will decline over time. Our business is dependent on our continued successful identification of productive fields and prospects and the identified locations in which we drill in the future may not yield oil or natural gas in commercial quantities.

Production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Accordingly, our current proved reserves will decline as these reserves are produced. As of December 31, 2022, our reserves-to-production (or reserve life) ratio for net proved reserves in Colombia, Chile, Brazil and Ecuador was 5.1 years. According to estimates, if on January 1, 2023, we ceased all drilling and development activities, including recompletions, refracs and workovers, our proved developed producing reserves base in Colombia, Chile, Brazil, and Ecuador would decline 29% during the first year.

Our future oil and natural gas reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing our current reserves and using cost-effective methods to find or acquire additional recoverable reserves. While we have had success in identifying and developing commercially exploitable fields and drilling locations in the past, we may be unable to replicate that success in the future. We may not identify any more commercially exploitable fields or successfully drill, complete or produce more oil or gas reserves, and the wells which we have drilled, and currently plan to drill within our blocks or concession areas, may not discover or produce any further oil or gas or may not discover or produce additional commercially viable quantities of oil or gas to enable us to continue to operate profitably. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations will be materially adversely affected.

We derive a significant portion of our revenues from sales to a few key customers.

In Colombia, we allocate our sales on a competitive basis to industry leading participants including traders and other producers. During 2022, the oil and gas production was sold to three clients which concentrate 97% of the Colombian subsidiaries' revenue (accounting for 90% of the consolidated revenue). Delivery points include wellhead and other locations on the Colombian pipeline system for the Llanos Basin production. The Putumayo Basin production is delivered to clients FOB in Esmeraldas, Ecuador, and to the Colombian pipeline system in case of contingencies in Ecuador that affect the transport through the Ecuadorian pipeline system. The outstanding contracts for Colombian production extend through the first half of 2023. We manage our counterparty credit risk associated to sales contracts by performing periodic evaluations of our counterparties' credit profile and, in certain contracts, including early payment conditions to minimize the exposure.

In Chile, the oil production is sold to ENAP, the State-owned oil and gas company (accounting for 1% of our consolidated revenue), and the gas production is sold to the local subsidiary of Methanex, a Canadian public company (accounting for 1% of our consolidated revenue).

In Brazil, all the hydrocarbons from the Manati Field were sold to Petrobras, the Brazilian State-owned company, which is the operator of the Manati Field (accounting for 2% of our consolidated revenue). See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Brazil—Petrobras Natural Gas Purchase Agreement."

In Ecuador, oil is transported through the Ecuadorean pipeline system, with Esmeraldas as the delivery point, and 100% of the sales are exported on a competitive basis to industry leading participants including traders and other producers. Sales of crude oil in Ecuador accounted for 1% of our consolidated revenue.

We entered into a crude oil purchase agreement with an oil producer in the Putumayo Basin. The volumes purchased are transported and exported alongside the Group's Putumayo Basin production. Sales of crude oil purchased from third parties accounted for 1% of our consolidated revenue.

If any of our buyers were to decrease or cease purchasing oil or gas from us, or if any of them were to decide not to renew their contracts with us or to renew them at a lower sales price, this could have a material adverse effect on our business, financial condition, and results of operations. For example, see "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Colombia" and "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Chile."

Our results of operations could be materially adversely affected by fluctuations in foreign currency exchange rates.

Although most of our revenues are denominated in US$, unfavorable fluctuations in foreign currency exchange rates for certain of our expenses in Colombia, Chile, Brazil and Ecuador could have a material adverse effect on our results of operations. An appreciation of local currencies can increase our costs and negatively impact our results from operations.

Because our Consolidated Financial Statements are presented in US$, we must translate revenues, expenses and income, as well as assets and liabilities, into US$ at exchange rates in effect during or at the end of each reporting period. Since December 2018, we decided to manage exposure to local currency fluctuation with respect to income tax balances in Colombia. Consequently, from time to time we entered into derivative financial instruments in order to anticipate any currency fluctuation with respect to estimated income taxes to be paid during the first half of the following year. As of December 31, 2022 and 2021, we had no currency risk management contracts in place. In January 2023, we entered into derivative financial instruments (zero-premium collars) with local banks in Colombia, for an amount equivalent to US$38.0 million in order to anticipate any currency fluctuation with respect to a portion of the estimated income taxes to be paid in April and June 2023.

There are inherent risks and uncertainties relating to the exploration and production of oil and natural gas.

Our performance depends on the success of our exploration and production activities and on the existence of the infrastructure that will allow us to take advantage of our oil and gas reserves. Oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that exploration activities will not identify commercially viable quantities of oil or natural gas. Our decisions to purchase, explore, develop, or otherwise exploit prospects or properties will depend in part on the evaluation of seismic and other data obtained through geophysical, geochemical and geological analysis, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

Furthermore, the marketability of any oil and natural gas production from our projects may be affected by numerous factors beyond our control. These factors include, but are not limited to, proximity and capacity of pipelines and other means of transportation, the availability of upgrading and processing facilities, equipment availability and government laws and regulations (including, without limitation, laws and regulations relating to prices, sale restrictions, taxes, governmental stake, allowable production, importing and exporting of oil and natural gas, environmental protection and health and safety). The effect of these factors, individually or jointly, cannot be accurately predicted, but may have a material adverse effect on our business, financial condition, and results of operations.

There can be no assurance that our drilling programs will produce oil and natural gas in the quantities or at the costs anticipated, or that our currently producing projects will not cease production, in part or entirely. Drilling programs may become uneconomic due to an increase in our operating costs or as a result of a decrease in market prices for oil and natural gas. Our actual operating costs or the actual prices we may receive for our oil and natural gas production may differ materially from current estimates. In addition, even if we are able to continue to produce oil and gas, there can be no assurance that we will have the ability to market our oil and gas production. See "—Our inability to access needed equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets and generate significant incremental costs or delays in our oil and natural gas production" below.

Our identified potential drilling location inventories are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled certain potential drilling locations as an estimate of our future multi-year drilling activities on our existing acreage. These identified potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy.

Our ability to drill and develop these identified potential drilling locations depends on a number of factors, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, the availability of gathering systems, marketing and transportation constraints, refining capacity, regulatory approvals and other factors. Because of the uncertainty inherent in these factors, there can be no assurance that the numerous potential drilling locations we have identified will ever be drilled or, if they are, that we will be able to produce oil or natural gas from these or any other potential drilling locations.

Our business requires significant capital investment and maintenance expenses, which we may be unable to finance on satisfactory terms or at all.

Because the oil and natural gas industry is capital intensive, we expect to make substantial capital expenditures in our business and operations for the exploration and production of oil and natural gas reserves. See "Item 4. Information on the Company—B. Business Overview—2023 Strategy and Outlook." We incurred capital expenditures of US$168.8 million and US$129.3 million during the years ended December 31, 2022 and 2021, respectively. See "Item 5. Operating and

Financial Review and Prospects—A. Operating Results—Factors Affecting our Results of Operations—Discovery and exploitation of reserves."

The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other equipment and services, and regulatory, technological and competitive developments. In response to changes in commodity prices, we may increase or decrease our actual capital expenditures. For example, as a result of the oil price decline in 2020 we adjusted the capital expenditures program for that year to US$65-75 million, approximately a 60% reduction from prior preliminary estimates (approximately US$180-200 million including capital expenditures for Amerisur assets).

We intend to finance our future capital expenditures through cash generated by our operations and potential future financing arrangements. However, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets.

If our capital requirements vary materially from our current plans, we may require further financing. In addition, we may incur significant financial indebtedness in the future, which may involve restrictions on other financing and operating activities. We may also be unable to obtain financing or financing on terms favorable to us. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. A significant reduction in cash flows from operations or the availability of credit could materially adversely affect our ability to achieve our planned growth and operating results.

Oil and gas operations contain a high degree of risk, and we may not be fully insured against all risks we face in our business.

Oil and gas exploration and production is speculative and involves a high degree of risk and hazards. Our operations may be disrupted by risks and hazards that are beyond our control and that are common among oil and gas companies, including environmental hazards, blowouts, industrial accidents, occupational safety and health hazards, technical failures, labor disputes, nationwide or regional social protests or blockades, unusual or unexpected geological formations, flooding, earthquakes and extended interruptions due to weather conditions, explosions and other accidents. For example, from April through July 2022, there were mobilizations and social protests in our operations in Putumayo (Colombia), with the purpose of interrupting oil activities to provoke a reaction from the government. This situation affected production in the Platanillo Block and caused delays in the drilling campaign planned for that block.

While we believe that we maintain customary insurance coverage for companies engaged in similar operations, we are not fully insured against all risks in our business because certain risks, such as public order related issues or natural disasters, are not subject to insurance coverage because they are not under our control. In addition, insurance that we do, and plan to, carry may contain significant exclusions from and limitations on coverage. We may elect not to obtain certain non-mandatory types of insurance if we believe that the cost of available insurance is excessive relative to the risks presented. The occurrence of a significant event or a series of events against which we are not fully insured, and any losses or liabilities arising from uninsured or underinsured events could have a material adverse effect on our business, financial condition or results of operations.

The development schedule of oil and natural gas projects is subject to cost overruns and delays.

Oil and natural gas projects may experience capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel, and oil field services. The cost to execute projects may not be properly established and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. The development of projects may be materially adversely affected by one or more of the following factors:

- shortages of equipment, materials and labor;

- fluctuations in the prices of construction materials;

- delays in delivery of equipment and materials;
- labor disputes;
- political events;
- title problems;
- obtaining easements and rights of way;
- blockades or embargoes;
- litigation;
- compliance with governmental laws and regulations, including environmental, health and safety laws and regulations;
- adverse weather conditions;
- unanticipated increases in costs;
- natural disasters;
- epidemics or pandemics;
- accidents;
- transportation;
- unforeseen engineering and drilling complications;
- delays during prior consultation processes;
- delays attributable to the operator of the project;
- environmental or geological uncertainties; and
- other unforeseen circumstances.

Any of these events or other unanticipated events could give rise to delays in development and completion of our projects and cost overruns.

For example, in 2022, the drilling and completion cost for the exploratory well Alea NW 1 in our Platanillo Block in Colombia was originally estimated at US$5.1 million, but the actual cost was US$5.9 million, mainly due to delays and overruns caused by a local community blockade.

Additionally, we may not be able to follow the development schedules we believe are optimal for blocks in which we are not the operator, such as the CPO-5 Block, which could adversely affect our financial condition and results of operations.

Delays in the construction and commissioning of projects or other technical difficulties may result in future projected target dates for production being delayed or further capital expenditures being required. These projects may often require the use of new and advanced technologies, which can be expensive to develop, purchase and implement and may not function as expected. Such uncertainties and operating risks associated with development projects could have a material adverse effect on our business, results of operations or financial condition.

Competition in the oil and natural gas industry is intense, which makes it difficult for us to attract capital, acquire properties and prospects, market oil and natural gas and secure trained personnel.

We compete with the major oil and gas companies engaged in the exploration and production sector, including state-owned exploration and production companies that possess greater financial and technical resources than we do for researching and developing exploration and production technologies and access to markets, equipment, labor and capital required to acquire, develop and operate our properties. We also compete for the acquisition of licenses and properties in the countries where we operate.

Our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources allow. Our competitors may also be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. In addition, there is substantial competition for capital available for investment in the oil and natural gas industry. As a result of each of the aforementioned, we may not be able to successfully compete in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel or raising additional capital, which could have a material adverse effect on our business, financial condition or results of operations. See “Item 4. Information on the Company—B. Business Overview—Our competition.”

Our estimated oil and gas reserves are based on assumptions that may prove inaccurate.

Our oil and gas reserves estimate in Colombia, Chile, Brazil and Ecuador as of December 31, 2022, are based on the D&M Reserves Report. Although classified as “proved reserves,” the reserves estimate set forth in the D&M Reserves Reports are based on certain assumptions that may prove inaccurate. DeGolyer and MacNaughton’s primary economic assumptions in estimates included oil and gas sales prices determined according to SEC guidelines, future expenditures and other economic assumptions (including interests, royalties and taxes) as provided by us.

Oil and gas reserves engineering is a subjective process of estimating accumulations of oil and gas that cannot be measured in an exact way, and estimates of other engineers may differ materially from those set out herein. Numerous assumptions and uncertainties are inherent in estimating quantities of proved oil and gas reserves, including projecting future rates of production, timing and amounts of development expenditures and prices of oil and gas, many of which are beyond our control. Post estimate drilling, testing and production results may require revisions. For example, if we are unable to sell our oil and gas to customers, this may impact the estimate of our oil and gas reserves. Accordingly, reserves estimates are often materially different from the quantities of oil and gas that are ultimately recovered, and if such recovered quantities are substantially lower than the initial reserves estimate, this could have a material adverse impact on our business, financial condition and results of operations.

Our inability to access needed equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets and generate significant incremental costs or delays in our oil and natural gas production.

Our ability to market our oil and natural gas production depends substantially on the availability and capacity of processing facilities, transportation facilities (such as pipelines, crude oil unloading stations and trucks) and other necessary infrastructure, which may be owned and operated by third parties. Our failure to obtain such facilities on acceptable terms or on a timely basis could materially harm our business. We may be required to shut down oil and gas wells because access to transportation or processing facilities may be limited or unavailable when needed. If that were to occur, we would be unable to realize revenue from those wells until arrangements were made to deliver the production to the market, which could cause a material adverse effect on our business, financial condition and results of operations. In addition, the shutting down of wells can lead to mechanical problems upon bringing the production back on-line, potentially resulting in decreased production and increased remediation costs. The exploitation and sale of oil and natural gas and liquids will also be subject to timely commercial processing and marketing of these products, which depends on the contracting, financing, building and operating of infrastructure by us and third parties.

In Colombia, producers of crude oil have historically suffered from trucking transportation logistics issues and limited pipeline and storage capacity, which cause delays in delivery and transfer of title of crude oil. To reduce this exposure, we and our partner in the Llanos 34 Block have constructed a flowline to evacuate crude oil from the Jacana field, reducing transportation costs, blockade risks and supporting our sustainable performance by reducing carbon emissions. During 2020, the Jacana-ODL flowline was converted into the Oleoducto del Casanare Pipeline ("ODCA") after receiving authorization from the Ministry of Energy and Mines to operate as such. We also inaugurated a truck unloading facility at Jacana Field and connected Tigana field to ODCA at the end of the year. During 2021, ODCA was a key element in the transport of crude production of our Llanos 34 Block. During May and June 2021, extensive protests and demonstrations across Colombia affected overall logistics and supply chains, restricting our crude oil transportation, drilling and the mobilization of personnel, equipment, and supplies. These events caused us to manage production curtailments that started in early May 2021, and normalized towards the end of June 2021. During 2022, the scheduled maintenance of the oil pipelines in Colombia frequently affected the logistics of evacuating the crude oil produced in the Llanos 34 and CPO-5 Blocks. As an alternative to these limitations in the use of the oil pipelines, trucks were used to transport the crude oil to alternative pumping stations closer to ports and refineries.

In the case of our Putumayo Basin production, we have also reduced our exposure to trucking issues by implementing the use of flowlines alongside trucking to gather our production at the Platanillo Block and transport it via the Oleoducto Binacional Amerisur ("OBA") pipeline that connects us to the Ecuador pipeline system.

Trucking transportation was key to our crude delivery strategy during 2022 and will continue to be part of our strategy in the future. Although we were able to enable alternative delivery points and transport oil by trucks, avoiding any significant negative impact in our production during this period, we cannot assure we would be able to do so in the future.

In Chile, we transport the crude oil we produce in the Fell Block by truck to ENAP's processing, storage and selling facilities at the Gregorio Refinery. As of the date of this annual report, ENAP purchases all the crude oil we produce in Chile. During 2022, ENAP had problems with its terminal's storage capacity. This made it necessary to limit, for 40 days, the production of the Fell Block to gas wells and to manage the associated liquids with internal storage capacity. We rely upon the continued good condition, maintenance, and accessibility of the roads we use to deliver the crude oil we produce. If the condition of these roads were to deteriorate or if they were to become inaccessible for any period of time, this could delay delivery of crude oil in Chile and materially harm our business.

In the Fell Block, we depend on ENAP-owned gas pipelines to deliver the gas we produce to Methanex, our main buyer. If ENAP's pipelines were unavailable to deliver, this could have a materially adverse effect on our ability to deliver and sell our product to Methanex, which could have a material adverse effect on our gas sales.

While Brazil has a well-developed network of hydrocarbon pipelines, storage and loading facilities, we may not be able to access these facilities when needed. Pipeline facilities in Brazil are often full and seasonal capacity restrictions may occur, particularly in natural gas pipelines. Our gas production from the Manati Field is transported on Petrobras-operated pipelines. If those pipelines became unavailable, our overall production levels in the Manati Field would be negatively impaired.

In Ecuador, our oil production is transported through the existing pipeline infrastructure. While the Ecuadorian pipeline system is well-developed and has operated reliably in the past, we cannot guarantee this will be the case in the future. Also, as production in Ecuador increases, available capacity may be limited. An inability to access transport capacity could adversely affect our production levels or the transport costs associated with getting our production to the market.

We may suffer delays or incremental costs due to difficulties in negotiations with landowners and local communities, including indigenous communities, where our reserves are located.

Access to the sites where we operate requires agreements (including easements, rights-of-way and access authorizations), primarily with the owners of the lands on which we intend to develop our operational projects. If we are unable to negotiate easements with landowners, we may have to go to court to obtain access to the sites of our operations, which may delay the progress of our operations at such sites. In Chile, for example, we have negotiated the necessary agreements for many of our current operations in the Magallanes Basin. In Brazil, if social unrest occurs, it may lead to delays or damage relating to our ability to operate the assets we have acquired or may acquire in the future.

In Colombia, although we have agreements with many landowners and are in negotiations with others, the economic expectations of landowners have generally increased, which may delay access to existing or future sites. Additionally, local communities and other stakeholders in the territory, such as workers' associations, trade unions and unions for activities related to the industry, are leading demands to the operators, beyond what is legally established, sometimes exerting pressures under de facto means or blockades to oil activities. Although oil and gas companies are managing these situations and stakeholder expectations in the territory, it ultimately becomes necessary to establish agreements for the viability of the operations, which on occasions translates into higher execution costs. Additionally, there are demands for improvements of transport infrastructure and the addressing of unsatisfied basic needs that have been historically ignored by the authorities and the fulfillment of such demands may be redirected towards the oil and gas companies.

In Putumayo (Colombia), where we have operating sites, there is presence of illegal groups which may pressure farmers to oppose the control and eradication of illicit crops, and instrumentalize the oil and gas industry with blockades, seeking to draw the attention of the national government and prevent the eradication of these crops.

As part of its international commitments, the Colombian government may seek to enhance the participatory phases of hydrocarbon projects, which could broaden the parameters of community participation and access to information and ultimately affect project timelines.

Furthermore, local communities’ expectations may increase because of several reforms the government has announced, including one to the country’s labor framework. If the government reforms do not meet the communities’ expectations, the pressure to reform may shift to the oil and gas industry.

The expectations and demands of local communities on oil and gas companies operating in Colombia may also increase. As a result, local communities have demanded that oil and gas companies invest in fixing and improving public access roads, compensate them for any damages related to use of such roads and, more generally, invest in infrastructure which is commonly paid for with public funds. Due to these circumstances, oil and gas companies in Colombia, including us, are now dealing with increasing difficulties resulting from instances of social unrest, temporary road blockades and conflicts with landowners.

In addition, community and indigenous protests and blockades may arise near our operations in Colombia, which could adversely affect our business, financial condition or results of operations. For example, on February 25, 2021, some communities in the Putumayo Basin protested against the government’s plans for the eradication of coca plantations in the area, blocking access to the Platanillo operations. Similar protests occurred between April and July 2022, sometimes affecting the continuity of operations in Platanillo.

Other legal proceedings such as land restitution, a judicial process implemented because of the peace agreement in Colombia, focus on returning illegally held land to its rightful owners, may delay access to future sites.

There can be no assurance that disputes with landowners and local communities or legal proceedings will not delay our operations or that any agreements we reach with such landowners and local communities or legal proceedings in the future will not require us to incur additional costs, thereby materially adversely affecting our business, financial condition and results of operations. Local communities may also protest or take actions that restrict or cause their elected government to restrict our access to the sites of our operations, which may have a material adverse effect on our operations at such sites.

In Ecuador, we have successfully, and on schedule, started exploration and production activities in 2022. However, a complex social and political environment regarding the development of extractive activities is also present there, as well as greater expectations and demands on oil and gas companies, which could lead to blockades and delays in the development of operational activities.

Under the terms of some of our various CEOPs, E&P contracts, production sharing agreements and concession agreements, we are obligated to drill wells, declare any discoveries, and file periodic reports to retain our rights and establish development areas. Failure to meet these obligations may result in the loss of our interests in the undeveloped parts of our blocks or concession areas.

To protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. In general, unless we make and declare discoveries within periods specified in our various special operation contracts (CEOPs, E&P contracts, production sharing agreements and concession agreements), our interests in the undeveloped parts of our license areas may lapse. Should the prospects we have identified under these contracts and agreements yield discoveries, we may face delays in drilling these prospects or be required to relinquish them. The costs to maintain or operate the CEOPs, E&P contracts, production sharing agreements and concession agreements over such areas may fluctuate and may increase significantly, and we may not be able to meet our commitments under such contracts and agreements on commercially reasonable terms or at all, which may force us to forfeit our interests in such areas. For example, in 2022, we transferred commitments from certain blocks to others and asked for termination of certain E&P contracts. See "Item 4. Information on the Company—B. Business Overview—Our operations—Operations in Colombia."

A significant amount of our reserves or production have been derived from our operations in certain blocks, including the Llanos 34, CPO-5, Platanillo and Llanos 32 Blocks in Colombia, the Fell Block in Chile, the BCAM-40 Concession in Brazil and the Espejo and Perico Blocks in Ecuador.

For the year ended December 31, 2022, the Llanos 34 Block contained 77.1% of our net proved reserves and generated 66.7% of our production, the CPO-5 Block contained 8.2% of our net proved reserves and generated 14.5% of our total production, the Platanillo Block contained 3.7% of our net proved reserves and generated 5.4% of our production, the Llanos 32 Block contained 2.7% of our net proved reserves and generated 1.1% of our production, the Fell Block contained 5.6% of our net proved reserves and generated 6.1% of our total production, the BCAM-40 Concession contained 2.2% of our net proved reserves and generated 3.9% of our production, the Perico Block contained 0.4% of our net proved reserves and generated 2.2% of our production and the Espejo Block contained 0.1% of our net proved reserves and generated 0.1% of our production. While our continuing expansion with new exploratory blocks incorporated in our portfolio means that the above-mentioned blocks may be expected to be a less significant component of our overall business, we cannot be sure that we will be able to continue diversifying our reserves and production. Resulting from these, any government intervention, impairment, or disruption of our production due to factors outside of our control or any other material adverse event in our operations in such blocks would have a material adverse effect on our business, financial condition, and results of operations.

Our contracts in obtaining rights to explore and develop oil and natural gas reserves are subject to contractual expiration dates and operating conditions, and our CEOPs, E&P contracts, production sharing agreements and concession agreements are subject to early termination in certain circumstances.

Under certain CEOPs, E&P contracts, production sharing contracts and concession agreements to which we are or may in the future become parties, we are or may become subject to guarantees to perform our commitments and/or to make payment for other obligations, and we may not be able to obtain financing for all such obligations as they arise. If such obligations are not complied with when due, in addition to any other remedies that may be available to other parties, this could result in cancelation of our CEOPs, E&P contracts, production sharing contracts and concession agreements or dilution or forfeiture of interests held by us. As of December 31, 2022, the aggregate outstanding amount of this potential liability for guarantees was US$96.7 million, mainly related to capital commitments in the Llanos 34, Llanos 87, CPO-5, PUT-8, and Platanillo Blocks in Colombia, the Campanario Block in Chile, and the Perico and Espejo Blocks in Ecuador. See "Item 4. Information on the Company—B. Business Overview—Our operations" and Note 33.2 to our Consolidated Financial Statements.

Additionally, certain CEOPs, E&P contracts, production sharing contracts and concession agreements to which we are or may in the future become a party are subject to set expiration dates. Although we may want to extend some of these contracts beyond their original expiration dates, there is no assurance that we can do so on terms that are acceptable to us or at all, although some of these agreements contain provisions enabling exploration extensions.

In Colombia, our E&P contracts are subject to early termination for a breach by the parties, a default declaration, application of any of the contracts' unilateral termination clauses or pursuant to termination clauses mandated by Colombian law. Anticipated termination declared by the ANH results in the immediate enforcement of monetary guaranties against us and may result in an action for damages by the ANH and/or a restriction on our ability to engage in contracts with the Colombian government during a certain period of time. See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Colombia—E&P contracts." To avoid the breach of an E&P contract due to unfulfillment of our exploration commitments, regulation gives us options such as the ability to transfer or credit those commitments to other E&P contracts, subject to meeting certain regulatory conditions.

In Chile, our CEOPs provide for early termination by Chile in certain circumstances, depending upon the phase of the CEOP. For example, pursuant to the Fell Block CEOP, Chile has the right to terminate the CEOP under certain circumstances if we fail to perform. If the Fell Block CEOP is terminated in the exploitation phase, we will have to transfer to the Chilean government, free of charge, any productive wells, and related facilities, provided that such transfer does not interfere with our abandonment obligations and excluding certain pipelines and other assets. See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Chile—CEOPs—Fell Block CEOP." If the CEOP is terminated early due to a breach of our obligations, we may not be entitled to compensation. Our CEOPs for the Campanario and Isla Norte Blocks, which are in the exploration phase, may be subject to early termination during this phase under certain circumstances, including if we fail to perform under the terms of the CEOPs, voluntarily relinquish all areas under the CEOPs or if we cease to operate in the CEOP area or declare bankruptcy. If these CEOPs are terminated within the exploration phase, we are released from all obligations under the CEOPs, except for obligations regarding the abandonment of fields, if any. See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Chile—CEOPs." There can be no assurance that the early termination of any of our CEOPs would not have a material adverse effect on us. In addition, according to the Chilean Constitution, Chile is entitled to expropriate our rights in our CEOPs for reasons of public interest. Although Chile would be required to indemnify us for such expropriation, there can be no assurance that any such indemnification will be paid in a timely manner or in an amount sufficient to cover the harm to our business caused by such expropriation.

In Brazil, concession agreements in the production phase generally may be renewed at the ANP's discretion for an additional period, provided that a renewal request is made at least 12 months prior to the termination of the concession agreement and there has not been a breach of the terms of the concession agreement. We expect that all our concession agreements will provide for early termination in the event of: (i) government expropriation for reasons of public interest; (ii) revocation of the concession pursuant to the terms of the concession agreement; or (iii) failure by us or our partners to fulfill all our respective obligations under the concession agreement (subject to a cure period). Administrative or monetary sanctions may also be applicable, as determined by the ANP, which shall be imposed based on applicable law and regulations. In the event of early termination of a concession agreement, the compensation to which we are entitled may not be sufficient to compensate us for the full value of our assets. Moreover, in the event of early termination of any concession agreement due to failure to fulfill obligations thereunder, we may be subject to fines and/or other penalties.

In Argentina, hydrocarbon exploration permits and exploitation concessions are subject to termination for: (a) failure to pay any annual license fees within three months after they are due; (b) failure to pay royalties within three months after they are due; (c) material and unjustified failure to comply with the specified obligations in respect to productivity, conservation, investments, works or special benefits; (d) repeated infringement of the obligations to submit demandable information, to facilitate inspections by the competent authority or to employ the proper techniques for the execution of the works; (e) failure to request an exploitation concession after a commercial discovery or to submit a development program after obtaining an exploitation concession; (f) the bankruptcy of the holder declared by a court; (g) the death or liquidation of the holder; or, (h) failure to comply with the obligation to transport hydrocarbons for third parties under open access conditions or repeated infringement of the tariff regime approved for such transport. Before declaring the termination under any of the grounds provided under items (a), (b), (c), (d), (e), and (h), notice shall be served, requiring the holder to remedy any such infringement. Upon expiration, relinquishment or termination of any permit or concession, the holder of such permit or concession shall surrender to the government the acreage together with all the improvements, facilities, wells and other equipment that may have been used in the performance of the activities.

In Ecuador, our production sharing contracts may be subject to early termination in case of breach of the obligations under the contract, non-performance of the exploratory commitments or unjustified suspension of the operations, lack of remediation of environmental damages or unauthorized assignment of a working interest under the production sharing contracts, among others, as specified under the laws of the contract. The declaration of an early termination is subject to prior due process, which would allow us to remedy any hypothetical breach claimed against us, or to present our defense allegations. A declaration of early termination will cause forfeiture of equipment and facilities and enforcement of monetary guarantees.

Early termination or nonrenewal of any CEOP, E&P contract, production sharing agreements or concession agreement could have a material adverse effect on our business, financial situation, or results of operations.

We sell all our natural gas in Chile to a single customer, who has in the past temporarily idled its principal facility.

For the year ended December 31, 2022, all our natural gas sales in Chile were made to Methanex under a long-term contract, the Methanex Gas Supply Agreement, which expires on December 31, 2026. During 2022, we negotiated an amendment to the gas supply contract to increase prices in the high methanol price cycle. Sales to Methanex represented 1% of our consolidated revenues for the year ended December 31, 2022. Methanex also buys gas from ENAP and a consortium that Methanex has formed with ENAP. If Methanex were to decrease or cease its purchase of gas from us, this would have a material adverse effect on our revenues derived from the sale of gas.

Methanex has two methanol producing facilities (trains) at its Cabo Negro production facility, near the city of Punta Arenas in southern Chile. Methanex has relied on local suppliers of natural gas, including ENAP, for its operations. We alone cannot supply Methanex with all the natural gas it requires for its operations. Over the past years, Argentina has been approving gas exports to Chile (including to Methanex) and other countries. These are annual authorizations which depend on the supply and demand balances of Argentina.

In the past, the Methanex plant was idled due to an anticipated insufficient supply of natural gas. In July 2020, the Methanex plant shut down because of a technical failure which affected our natural gas production and sales for 10 days. See "Item 4. Information on the Company—B. Business Overview—Marketing and delivery commitments—Chile."

However, we cannot be sure that Methanex will continue to purchase our gas, including the above committed levels, or that its efforts to reduce the risk of future shut-downs will be successful, which could have a material adverse effect on our gas revenues. Additionally, we cannot be sure that Methanex will have sufficient supplies of gas to operate its plant and continue to purchase our gas production or that methanol prices would be sufficient to cover the operating costs. We cannot be sure that we would be able to sell our gas production to other parties or on similar terms, which could have a material adverse effect on our business, financial condition, and results of operations.

We are not, and may not be in the future, the sole owner or operator of all our licensed areas and do not, and may not in the future, hold all the working interests in some of our licensed areas. Therefore, we may not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and, to an extent, any non-wholly owned, assets.

As of December 31, 2022, we are not the operator of 24% or sole owner of 47% of the blocks included in our portfolio. See "Item 4. Information on the Company—B. Business Overview—Operations in Colombia", "—Operations in Chile", "—Operations in Brazil", "—Operations in Argentina" and "—Operations in Ecuador."

In addition, the terms of the joint operations agreements or association agreements governing our other partners' interests in almost all of the blocks that are not wholly owned or operated by us require that certain actions be approved by supermajority vote. The terms of our other current or future license or venture agreements may require at least the majority of working interests to approve certain actions. As a result, we may have limited ability to exercise influence over operations or prospects in the blocks operated by our partners, or in blocks that are not wholly owned or operated by us. A breach of contractual obligations by our partners who are the operators of such blocks could eventually affect our rights in exploration and production contracts in some of our blocks in Colombia, Brazil, Argentina, and Ecuador. Our dependence on our partners could prevent us from achieving our target returns for those discoveries or prospects.

Moreover, as we are not the sole owner or operator of all our properties, we may not be able to control the timing of exploration or development activities or the amount of capital expenditures and may therefore not be able to carry out our key business strategies of minimizing the cycle time between discovery and initial production at such properties. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other block partners in drilling wells;
- the scheduling, pre-design, planning, design and approvals of activities and processes;
- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations on some of our license areas may cause a material adverse effect on our financial condition and results of operations.

For example, we are not the operator of the CPO-5 Block, and do not control the execution of the development schedule. Any delays in the execution schedule of the CPO-5 Block could have a material adverse effect in our financial condition and results of operation.

Acquisitions that we have completed, and any future acquisitions, strategic investments, partnerships, or alliances could be difficult to integrate and/or identify, could divert the attention of key management personnel, disrupt our business, dilute stockholder value and adversely affect our financial results, including impairment of goodwill and other intangible assets.

One of our principal business strategies includes acquisitions of properties, prospects, reserves and leaseholds and other strategic transactions, including in jurisdictions in which we do not currently operate. The successful acquisition and integration of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices;
- development and operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review and the review of advisors and independent reserves engineers will not reveal all existing or potential problems, nor will it permit us or them to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental conditions are not necessarily observable even when an inspection is undertaken. We, advisors or independent reserves engineers may apply different assumptions when assessing the same field. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis. Even in those circumstances in which we have contractual indemnification rights for pre-closing liabilities, it remains possible that the seller will not be able to fulfill its contractual obligations. There can be no assurance that problems related to the assets or management of the companies and operations we have acquired, or operations we may acquire or add to our portfolio in the future, will not arise in future, and these problems could have a material adverse effect on our business, financial condition, and results of operations.

Significant acquisitions, and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with ours while carrying on our ongoing business;
- contingencies and liabilities that could not be or were not identified during the due diligence process, including with respect to possible deficiencies in the internal controls of the acquired operations; and
- challenge of attracting and retaining personnel associated with acquired operations.

It is also possible that we may not identify suitable acquisition targets or strategic investment, partnership, or alliance candidates. Our inability to identify suitable acquisition targets, strategic investments, partners or alliances, or our inability to complete such transactions, may negatively affect our competitiveness and growth opportunities. Moreover, if we fail to properly evaluate acquisitions, alliances, or investments, we may not achieve the anticipated benefits of any such transaction, and we may incur costs in excess of what we anticipate.

Future acquisitions financed with our own cash could deplete the cash and working capital available to adequately fund our operations. We may also finance future transactions through debt financing, the issuance of our equity securities, existing cash, cash equivalents or investments, or a combination of the foregoing. Acquisitions financed with the issuance of our equity securities could be dilutive, which could affect the market price of our stock. Acquisitions financed with debt could require us to dedicate a substantial portion of our cash flow to principal and interest payments and could subject us to restrictive covenants.

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. For the year ended December 31, 2022, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first day-of-the-month price for the preceding 12 months. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations, taxation or the taxation invariability provisions in our CEOPs.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our proved undeveloped reserves ultimately may not be developed or produced.

As of December 31, 2022, 74% of our net proved reserves are developed. Development of our undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Additionally, delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the standardized measure value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves, and may result in some projects becoming uneconomic, causing the quantities associated with these uneconomic projects to no longer be classified as reserves. This was due to the uneconomic status of the reserves, given the proximity to the end of the concessions for these blocks, which does not allow for future capital investment in the blocks. There can be no assurance that we will not experience similar delays or increases in costs to drill and develop our reserves in the future, which could result in further reclassifications of our reserves.

We are exposed to the credit risks of our customers and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.

Our customers may experience financial problems that could have a significant negative effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce the performance of obligations owed to us under contractual arrangements.

The combination of declining cash flows as a result of declines in commodity prices, a reduction in borrowing basis under reserves-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payments or perform on their obligations to us.

Some of our customers may be highly leveraged, and, in any event, are subject to their own operating expenses. Therefore, the risk we face in doing business with these customers may increase. Other customers may also be subject to regulatory changes, which could increase the risk of defaulting on their obligations to us. Financial problems experienced by our customers could result in the impairment of our assets, a decrease in our operating cash flows and may also reduce or curtail our customers' future use of our products and services, which may have an adverse effect on our revenues and may lead to a reduction in reserves.

These customer risks may be adversely impacted by an endemic or pandemic disease, including a potential resurgence of the COVID-19 pandemic.

Our operations are subject to operating hazards, including extreme weather events, which could expose us to potentially significant losses.

Our operations are subject to potential operating hazards, extreme weather conditions and risks inherent to drilling activities, seismic registration, exploration, production, development and transportation and storage of crude oil, such as explosions, fires, car and truck accidents, floods, labor disputes, social unrest, community protests or blockades, guerilla attacks, security breaches, pipeline ruptures and spills and mechanical failure of equipment at our or third-party facilities. Any of these events could have a material adverse effect on our exploration and production operations or disrupt transportation or other process-related services provided by our third-party contractors.

We are highly dependent on certain members of our management and technical team, including our geologists and geophysicists, and on our ability to hire and retain new qualified personnel.

The ability, expertise, judgment and discretion of our management and our technical and engineering teams are key in discovering and developing oil and natural gas resources. Our performance and success are dependent to a large extent upon key members of our management and exploration team, and their loss or departure would be detrimental to our future success. In addition, our ability to manage our anticipated growth depends on our ability to recruit and retain qualified personnel. Our ability to retain our employees is influenced by the economic environment and the remote locations of our exploration blocks, which may enhance competition for human resources where we conduct our activities, thereby increasing our turnover rate. There is strong competition in our industry to hire employees in operational, technical, and other areas, and the supply of qualified employees is limited in the regions where we operate and throughout Latin America generally. The loss of any of our key management or other key employees of our technical team or our inability to hire and retain new qualified personnel could have a material adverse effect on us.

We and our operations are subject to numerous environmental, social, health and safety laws, regulations and rulings, which may result in material liabilities and costs.

We and our operations are subject to various international, foreign, federal, state, and local environmental, health and safety laws and regulations governing, among other things, the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use, transportation and disposal of regulated materials; and human health and safety. Our operations are also subject to certain environmental risks that are inherent in the oil and gas industry, and which may arise unexpectedly and result in material adverse effects on our business, financial condition, and results of operations. Breach of environmental laws could result in environmental administrative investigations and/or lead to the termination of our concessions and contracts. Other potential consequences include fines and/or criminal or civil environmental actions. For instance, non-governmental organizations may bring actions against us or other oil and gas companies in order to, among other things, halt our activities in any of the countries in which we operate or require us to pay fines. Additionally, in Colombia, environmental licenses are administrative acts subject to class actions that could eventually result in their cancellation, with potential adverse impacts on our E&P contracts.

The Regional Agreement on Access to Information, Public Participation and Justice in Environmental Matters in Latin America and the Caribbean, also known as the Escazú Agreement, is an international human rights treaty that was signed by all the countries in which we operate and has been ratified by all, except for Brazil, where pressure has been growing for the government to ratify. We expect the countries where the agreement has been ratified will proceed to regulate the agreement and such regulations may include additional processes on participation and information, which could directly affect our operations.

We are subject to national and regional environmental regulations and specific environmental requirements as part of the licenses and permits that we must obtain for our operations. We have mechanisms to assure the fulfillment of all those legal obligations such as a permanent external audit, a dedicated environmental team, and our environmental management system. The evidence of the fulfillment of such obligations is consolidated in the yearly environmental reports that are issued to the environmental authorities and correspond to public information. In addition, we are subject to yearly visits by the environmental national authority. Although we fulfill the requirements, sometimes we have not been and may not be at all times in complete compliance with some of them due to causes not attributable to us. This is the case of the offset obligations we have to implement to compensate the residual impacts that cannot be avoided, minimized or restored, in which we have to consider a concertation process with different stakeholders that could take more time than what the regulation provides. Nevertheless, we report the progress and we define action plans to demonstrate our diligence and reduce the possibility of sanctions, penalties or fines related to a delay in our fulfillment of the obligations, which could have a material adverse effect on our business, financial condition or results of operations.

We have contracted with and intend to continue to hire third parties to perform services related to our operations. We could be held liable for some or all environmental, health and safety costs and liabilities arising out of our actions and omissions as well as those of our block partners, third-party contractors, predecessors, or other operators. To the extent we do not address these costs and liabilities or if we do not otherwise satisfy our obligations, our operations could be suspended, terminated, or otherwise adversely affected. Although we screen our contractors regarding their compliance on several issues, there is a risk that we may contract with third parties with unsatisfactory environmental, health and safety records or that our contractors may be unwilling or unable to cover any losses associated with their acts and omissions.

Releases of regulated substances may occur and can be significant. Under certain environmental laws and regulations applicable to us in the countries in which we operate, we could be held responsible for all the costs relating to any contamination at our past and current facilities and at any third-party waste disposal sites used by us or on our behalf. Pollution resulting from waste disposal, emissions and other operational practices might require us to remediate contamination, or retrofit facilities, at substantial cost. We also could be held liable for any and all consequences arising out of human exposure to such substances or for other damage resulting from the release of hazardous substances to the environment, property or to natural resources, or affecting endangered species or sensitive environmental areas. We are currently required to, and in the future may need to, plug and abandon sites in certain blocks in each of the countries in which we operate, which could result in substantial costs.

In addition, we expect continued and increasing attention to climate change issues. Various countries and regions have agreed to regulate emissions of greenhouse gases including methane (a primary component of natural gas) and carbon dioxide (a byproduct of oil and natural gas combustion). The regulation of greenhouse gases and the physical impacts of climate change in the areas in which we, our customers and the end-users of our products operate could adversely impact our operations and the demand for our products.

We have set a target to reduce operational Scope 1 and 2 GHG emissions by 35-40 percent by year-end 2025 and by 40-60 percent by year-end 2030 from a 2020 baseline. We also have a long-term ambition to achieve net zero Scope 1 and 2 GHG emissions from operations by 2050. Our ability to meet these targets (particularly the 2030 GHG reduction target and the 2050 net zero ambition) is subject to numerous risks and uncertainties and actions taken in implementing such target and ambition may also expose us to certain additional and/or heightened financial and operational risks. Furthermore, the long-term ambition of reaching net zero emissions by 2050 is inherently less certain due to the longer timeframe and certain factors outside of our control, including the commercial application of future technologies that may be necessary to achieve this long-term ambition. A reduction in GHG emissions relies on, among other things, the ability to develop, access and implement commercially viable and scalable emission reduction strategies and related technology and products. If we are unable to implement these strategies and technologies as planned without negatively impacting expected operations or cost structures, or such strategies or technologies do not perform as expected, we may be unable to meet the 2025 and 2030 GHG reduction targets or the 2050 net zero emissions ambition on the current timelines, or at all.

In addition, achieving the 2025 and 2030 GHG reduction targets and the 2050 net zero ambition relies on a stable regulatory framework and will require capital expenditures and resources, with the potential that actual costs may differ from the original estimates and the differences may be material. Furthermore, the cost of investing in emissions-reduction technologies, and the resultant change in the deployment of resources and focus, could have a negative impact on future operating and financial results.

Environmental, health and safety laws and regulations are complex and change frequently, and our costs of complying with such laws and regulations may adversely affect our results of operations and financial condition. See “Item 4. Information on the Company—B. Business Overview—Health, safety and environmental matters” and “Item 4. Information on the Company—B. Business Overview—Industry and regulatory framework.”

Changing investor sentiment towards fossil fuels may affect our operations, impact the price of our common shares and limit our access to financing and insurance.

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, the impact of oil and gas operations on the environment, environmental damage relating to spills of petroleum products during transportation and indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry.

As a result of these concerns, some institutional, retail, and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from our Board, management and employees. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in our Company or not investing in our Company at all.

Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, our Company, may result in limiting our access to capital and insurance, increasing the cost of capital and insurance, and decreasing the price and liquidity of our common shares even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of our assets which may result in an impairment charge.

Legislation and regulatory initiatives relating to hydraulic fracturing and other drilling activities for unconventional oil and gas resources could increase the future costs of doing business, cause delays or impede our plans, and materially adversely affect our operations.

Hydraulic fracturing of unconventional oil and gas resources is a process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate a higher flow of hydrocarbons into the wellbore. We may eventually contemplate, after due environmental approvals, such use of hydraulic fracturing in the production of oil and natural gas from certain reservoirs. Legislation and regulatory initiatives relating to hydraulic fracturing and other drilling activities for unconventional oil and gas resources could increase the future costs of doing business, cause delays or impede our plans, and materially adversely affect our operations.

In Colombia, during the second half of 2022, the Council of State issued a decision by which it denied the claims that were seeking nullity of the regulation for "non-conventional hydrocarbons". Therefore, the regulation for unconventional oil and gas resources in Colombia is in force and with full effects. However, the government is seeking to prohibit fracking techniques in Colombia and, during the second half of 2022, a law project to forbid fracking and exploitation of unconventional hydrocarbons was filed. The law project is expected to be debated in Congress in 2023, however, in light of the priority the Government has given to reforms in other sectors, such as health and labor, it is uncertain when the debate is expected to occur, and the debate may be delayed. The non-conventional pilot projects (Kalé and Platero in Valle Medio del Magdalena) which were led by ANH have been suspended by Ecopetrol while it waits for news and guidelines from the government with respect to these types of projects. The environmental license for Kalé has already been obtained and the environmental license for Platero is in process. Drilling in these pilot projects was expected to begin in 2023. However due to recent announcements from the government, Ecopetrol has decided to stand by and stop investment until there are further advances in the government's policies. The way in which these pilot projects were carried out would surely impact the future of these resources in Colombia.

We currently are not aware of any proposals in Chile, Brazil or Ecuador to regulate hydraulic fracturing beyond the regulations already in place. However, various initiatives in other countries with substantial shale gas resources have been or may be proposed or implemented to, among other things, regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. If any of the countries in which we operate adopts similar laws or regulations, which is something we cannot predict right now, such adoption could significantly increase the cost of, impede or cause delays in the implementation of any plans to use hydraulic fracturing for unconventional oil and gas resources.

Our indebtedness and other commercial obligations could adversely affect our financial health and our ability to raise additional capital and prevent us from fulfilling our obligations under our existing agreements and borrowing of additional funds.

As of December 31, 2022, we had US$497.6 million outstanding amount of indebtedness on a consolidated basis, consisting of our Notes due 2027.

Our indebtedness could:

- limit our capacity to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of our debt instruments, including restrictive covenants and borrowing conditions, could result in an event of default under the agreements governing our indebtedness;

- require us to dedicate a substantial portion of our cash flow from operations to the payments on our indebtedness, thereby reducing the availability of our cash flow to fund acquisitions, working capital, capital expenditures and other general corporate purposes;

- place us at a competitive disadvantage compared to certain of our competitors that have less debt;

- limit our ability to borrow additional funds;

- in the case of our secured indebtedness, if any, lose assets securing such indebtedness upon the exercise of security interests in connection with a default;

- make us more vulnerable to downturns in our business or the economy; and

- limit our flexibility in planning for, or reacting to, changes in our operations or business and the industry in which we operate.

The indenture governing our Notes due 2027 includes covenants restricting dividend payments. For a description, see "Item 5. Operating and Financial Review and Prospects—B. Liquidity and Capital Resources—Indebtedness."

As a result of these restrictive covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs. We have in the past been unable to meet incurrence tests under the indenture governing our prior notes, which limited our ability to incur indebtedness. Failure to comply with the restrictive covenants included in our Notes due 2027 would not trigger an event of default.

Similar restrictions could apply to us and our subsidiaries when we refinance or enter into new debt agreements which could intensify the risks described above.

Our business could be negatively impacted by security threats, including cybersecurity threats as well as other disasters, and related disruptions.

The global cyber-threats constantly evolve and the oil and gas industry is exposed to it.

Digital technologies have become an integral part of our business. The oil and gas industry has become increasingly dependent on computer and telecommunications systems to conduct exploration, development, and production activities.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also escalated in the world. Our industry is subject to fast-evolving risks from cyber threat actors, including states, criminals, terrorists, hacktivists, and insiders.

We have incorporated new capabilities to protect critical systems and sensitive information from cyber-attacks. We have been creating effective and disruptive ways of leveraging technology using world-class capabilities like Cloud Computing, Artificial Intelligence, Machine Learning, Internet of Things, Big Data and Robotic Computing. These new capabilities support our strategy to optimize processes, take effective decisions based on relevant and up to date data, reduce costs, increase oil production, mitigate risks, and improve our carbon blueprint. These projects have a relevant component of cybersecurity protection to reduce the risk of malicious attacks.

We have strengthened the security capabilities not only by incorporating new cybersecurity talent but also by optimizing our platforms using the best cybersecurity protection systems available in the market like Crowd Strike, Palo Alto firewalls, Multifactor Authentication, Microsoft Defense, Darktrace, Tanium, DNA Center, GRC, SDWAN among others, reducing the probability of accessing, changing, or destroying sensitive information; extorting money from users; or interrupting normal business processes.

Since we have incorporated the hybrid work model, multiple measures related to remote access and teleworking of employees and contractors, have been strengthened using security tools and best practices. Our employees will continue to be cyber-threat targets and hence, we have coordinated for our employees to participate in several workshops led by reputable speakers to generate consciousness about digital threats and we have implemented different platforms like Multifactor Authentication, geo-reference access and user behavior monitoring.

After a successful NIST framework implementation and the Security Operation Center 24/7 incorporation in 2022, different assessments with reputable companies were made in GeoPark showing that our cybersecurity platforms, processes and controls are above the industry average.

Although we have implemented a strong cyber security strategy and procedures to prevent and assure the confidentiality, availability, and security of our data, we cannot guarantee that these measures will be enough for this purpose. Cyber-attacks, whose techniques are regularly renewed, are becoming more and more sophisticated.

Therefore, it is necessary to continue identifying and fixing any technical vulnerabilities and weaknesses in the operating processes, as well as to continue strengthening capabilities to detect and react to incidents. This includes the need to strengthen security controls in the supply chain (from our partners and other third parties), as well as to ensure the security of the services in the cloud.

As a result of the circumstances brought by the COVID-19 pandemic, security measures related to remote access and teleworking of employees and collaborators have been reviewed and strengthened, but no assurance can be provided that such security measures will be effective.

A breach or failure of our digital infrastructure – including control systems – due to breaches of our cyber defenses, or those of third parties, negligence, intentional misconduct, or other reasons, could seriously disrupt our operations. This could result in the loss or misuse of data or sensitive information, injury to people, disruption to our business, harm to the environment or our assets, legal or regulatory breaches and legal liability.

Furthermore, the rapid detection of attempts to gain unauthorized access to our digital infrastructure, often through the use of sophisticated and coordinated means, is a challenge we must face and any delay or failure to detect cyber incidents could compound these potential harms. This could result in significant losses including the cost of remediation and reputational consequences.

Our employees have been and will continue to be targeted by parties using fraudulent “spam”, “scam”, “phishing” and “spoofing” emails to misappropriate information or to introduce viruses or other malware programs to our computers.

Although to date cyber-attacks have not had a material impact on our operations or financial results, there can be no assurance that we will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident.

As cyber threats continue to evolve, we may be required to expend significant additional resources to continue modifying and enhancing our protective measures and to investigate and remediate any information security vulnerabilities.

We also have in place a cybersecurity insurance policy, to get coverage and indemnification for a potential cyber-attack or data breach. However, no assurances can be made as to whether the insurance policy will be enough to cover all our potential liability.

We operate in an industry with climate related risks.

According to the World Bank’s Climate Change Knowledge Portal, “Colombia ranks 10th globally in terms of economic risk posed by three or more climate related hazards. The country has the highest recurrence of extreme events in South America, with 84 percent of the population and 86 percent of its assets in areas exposed to two or more hazards.” Similarly, “Ecuador is at risk to several natural hazards, including floods, landslides, droughts, and earthquakes.” In 2022, we worked on identifying climate related risks to our operations. Flooding and extreme winds were identified as the most critical. Landslides, river erosion and electrical storms were also determined to be potential climate related risks. We are updating the potential financial impacts of the materialization of these risks and our existing management plan as part of our ongoing corporate risk evaluation.

We operate in areas of significant biodiversity value.

Some of our operations are in or adjacent to areas with significant biodiversity value, some of which are being considered for designation as conservation or protected areas. This may cause alterations to our plans with regards to the use we can give the land, may increase viability costs, and delay our timelines. We carry out detailed due diligence processes to mitigate the potential impacts derived from this risk, but there are factors outside of our control, such as local politics and political decisions.

We operate in areas that have historical and current ties to indigenous peoples.

We operate in highly culturally diverse areas, which brings us and our operations in close contact with different indigenous groups. This means we carry out prior consultation processes aligned with the highest human rights standards, including IFC's Environmental and Social Performance Standards, and particularly PS7: Indigenous Peoples.

We respect the existing legal framework for the protection and safeguard of the rights of indigenous groups, both in terms of the legal provisions of the countries in which we operate, as well as the provisions of Convention 169 of the International Labor Organization (ILO), which aims to ensure the rights of indigenous and tribal peoples to their territory and the protection of their cultural, social, and economic values. With regards to prior consultation, we recognize that it is a fundamental instrument for the survival of indigenous communities, for the preservation of cultural diversity and for the conservation of natural resources. It also contributes to the protection of their right to self-determination, self-government, and the development of projects and their own life plans. We work closely with government authorities from the first moment we arrive in any territory, to carry out any process or protocol required for a prior consultation. We recognize that our entry and permanence in the territories is determined by the social license granted to us by the indigenous communities that inhabit them, and that we will make every effort to gain their trust and acceptance to achieve a mutually beneficial relationship in the long term.

During 2021 and 2022, as part of our exploration projects and based on certifications of the origin of prior consultation issued by the directorate of the national authority for prior consultation of the Ministry of the Interior, we have made advancements in the development of consultation processes in the department of Meta with the Resguardo, Turpial, La Victoria and Wacoyo communities for the 3D seismic acquisition program in the Llanos 86 and Llanos 104 Blocks. This consultation is currently in the follow-up stage. We are also advancing the prior consultation process for the Golondrina development area project in the Llanos 86 and Llanos 104 Blocks. Similarly, we are making advancements in the preliminary consultations for the 2D and 3D seismic acquisition program in the Coati Block with the indigenous communities of Resguardo, Santa Rosa del Guamuez, Yarinal, San Marcelino, Campo Alegre del Afilador and Parcialidad Nueva Palestina in the department of Putumayo.

Exploration blocks in the Putumayo area carry significant costs related to biodiversity management and reputational risk due to overlapping claims of rightful ownership.

With the acquisition of Amerisur in January 2020, we have assumed significant and unpredictable costs for biodiversity management if we are to comply with best industry practices aligned to IFC's Performance Standard 6. Costs related to mitigation measures to protect the habitat could be greater than currently anticipated due to unanticipated findings in baseline biodiversity studies. Nevertheless, we design our exploration and production projects while considering the conditions of the environment and avoiding any disruption to natural forest coverage and ecosystems.

Nine out of twelve of the oil and gas development and exploration blocks in the Putumayo area in Colombia overlap with indigenous territories that are either formalized or are being considered for formal titling of tribal lands under the Colombian land restitution law.

Risks relating to the countries in which we operate

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate and in which we may operate in the future.

All of our current operations are located in South America. If local, regional or worldwide economic trends adversely affect the economy of any of the countries in which we have investments or operations, our financial condition and results from operations could be adversely affected.

The Economic Commission for Latin America and the Caribbean (ECLAC) has forecasted that the regional growth in 2023 will be a third of the rate forecast for 2022 (going from 3.7% in 2022 to 1.3% in 2023), because of external uncertainties such as the outcome of the armed conflict in Ukraine and domestic restrictions, including restrictive monetary policies, greater limitations on fiscal spending and lower levels of consumption and investment. The ECLAC recommends governments review their tax expenditures, carry out reforms to increase tax collection and focus on making public spending more efficient and effective. The measures that countries may take to address a challenging economic context may affect our operations and results. The possibility of continued inflation and slow growth may also cause social unrest in the countries where we operate.

In Colombia, the government has announced a broad labor reform, which, if passed in its entirety and as proposed, may have adverse impacts on our operating costs and may require changes to our labor contracts that can cause delays in our internal processes.

Oil and natural gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes in energy policies or the personnel administering them), changes in laws and policies governing operations of foreign-based companies, expropriation of property, cancellation or modification of contract rights, revocation of consents or approvals, the obtaining of various approvals from regulators, foreign exchange restrictions, price controls, currency fluctuations, royalty increases and other risks arising out of foreign governmental sovereignty, as well as to risks of loss due to civil strife, acts of war and community-based actions, such as protests or blockades, guerilla activities, terrorism, acts of sabotage, territorial disputes and insurrection. In addition, we are subject both to uncertainties in the application of the tax laws in the countries in which we operate and to possible changes in such tax laws (or the application thereof), each of which could result in an increase in our tax liabilities. These risks are higher in developing countries, such as those in which we conduct our activities. For example, our operations in Colombia represented 91.7% of our net proved reserves as of December 31, 2022, 87.4% of our production in 2022 and 93.2% of our consolidated revenues in 2022.

The main economic risks we face and may face in the future because of our operations in the countries in which we operate include the following:

- difficulties incorporating movements in international prices of crude oil and exchange rates into domestic prices;
- the possibility that a deterioration in Colombia's, Chile's, Brazil's and Ecuador's relations with multilateral credit institutions, such as the International Monetary Fund, will impact negatively on capital controls, and result in a deterioration of the business climate;
- inflation, exchange rate movements (including devaluations), exchange control policies (including restrictions on remittance of dividends), price instability and fluctuations in interest rates;
- liquidity of domestic capital and lending markets;
- tax policies; and
- the possibility that we may become subject to restrictions on repatriation of earnings from the countries in which we operate in the future.

In addition, our operations in these areas increase our exposure to risks of guerilla and other illegal armed group activities, social unrest, local economic conditions, political disruption, civil disturbance, community protests or blockades, expropriation, tribal conflicts and governmental policies that may: disrupt our operations; require us to incur greater costs for security; restrict the movement of funds or limit repatriation of profits; lead to U.S. government or international sanctions; limit access to markets for periods of time; or influence the market's perception of the risk associated with investments in these countries.

Some countries in the geographic areas where we operate have experienced, and may experience in the future, political instability, and losses caused by these disruptions may not be covered by insurance. For example, during 2022, Colombia and Ecuador experienced social and political turmoil, including riots, nationwide protests, strikes and street demonstrations against their governments which led to acts of violence and social and political tensions. Future protests could adversely and materially affect the Colombian and Ecuadorian economy and our businesses in those countries. Consequently, our exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on our results of operations and financial condition. We cannot guarantee that current programs and policies that apply to the oil and gas industry will remain in effect.

Our operations may also be adversely affected by laws and policies of the jurisdictions, including Bermuda, Colombia, Chile, Brazil, Argentina, Ecuador, Spain, the United Kingdom and other jurisdictions in which we do business, that affect foreign trade and taxation, and by uncertainties in the application of, possible changes to (or to the application of) tax laws in these jurisdictions. For example, in 2022, the Colombian government issued a tax reform. See Note 16 to our Consolidated Financial Statements

With regards to Chile, although our CEOPs have protection against tax changes through invariability tax clauses, potential issues may arise on certain aspects not clearly defined in current or future tax reforms.

Changes in any of these laws or policies or the implementation thereof, and uncertainty over potential changes in policy or regulations affecting any of the factors mentioned above or other factors in the future may increase the volatility of domestic securities markets and securities issued abroad by companies operating in these countries, which could materially and adversely affect our financial position, results of operations and cash flows. Furthermore, we may be subject to the exclusive jurisdiction of courts outside the United States or may not be successful in subjecting non-U.S. persons to the jurisdiction of courts in the United States, which could adversely affect the outcome of such dispute. Changes in tax laws may result in increases in our tax payments, which could materially adversely affect our profitability and increase the prices of our products and services, restrict our ability to do business in our existing and target markets and cause our results of operations to suffer. There can be no assurance that we will be able to maintain our projected cash flow and profitability following any increase in taxes applicable to us and to our operations.

We depend on maintaining good relations with the respective host governments and national oil companies in each of our countries of operation.

The success of our business and the effective operation of the fields in each of our countries of operation depend upon continued good relations and cooperation with applicable governmental authorities and agencies, including national oil companies such as Ecopetrol, ENAP, Petrobras, YPF and Petroecuador. For instance, for the year ended December 31, 2022, 100% of our crude oil and condensate sales in Chile were made to ENAP, the Chilean state-owned oil company. In addition, our Brazilian operations in BCAM-40 Concession provide us with a long-term off-take contract with Petrobras, the Brazilian state-owned company that covers 100% of net proved gas reserves in the Manati Field, one of the largest non-associated gas fields in Brazil. If we, the respective host governments and the national oil companies are not able to cooperate with one another, it could have an adverse impact on our business, operations and prospects.

Oil and natural gas companies in Colombia, Chile, Brazil and Ecuador do not own any of the oil and natural gas reserves in such countries.

Under Colombian, Chilean, Brazilian and Ecuadorian law, all onshore and offshore hydrocarbon resources in these countries are owned by the respective sovereign. Although we are the operator of the majority of the blocks and concessions in which we have a working and/or economic interest and generally have the power to make decisions as how to market the hydrocarbons we produce, the Colombian, Chilean, Brazilian and Ecuadorian governments have full authority to determine the rights, royalties or compensation to be paid by or to private investors for the exploration or production of any hydrocarbon reserves located in their respective countries.

If these governments were to restrict or prevent concessionaires, including us, from exploiting oil and natural gas reserves, or otherwise interfered with our exploration through regulations with respect to restrictions on future exploration and production, price controls, export controls, foreign exchange controls, income taxes, expropriation of property, environmental legislation or health and safety, this could have a material adverse effect on our business, financial condition and results of operations.

Additionally, we are dependent on receipt of government approvals or permits to develop the concessions we hold in some countries. There can be no assurance that future political conditions in the countries in which we operate will not result in changes to policies with respect to foreign development and ownership of oil and gas, environmental protection, health and safety or labor relations, which may negatively affect our ability to undertake exploration and development activities in respect of present and future properties, as well as our ability to raise funds to further such activities. Any delays in receiving government approvals in such countries may delay our operations or may affect the status of our contractual arrangements or our ability to meet contractual obligations.

Oil and gas operators are subject to extensive regulation in the countries in which we operate.

The Colombian, Chilean, Brazilian and Ecuadorian hydrocarbons industries are subject to extensive regulation and supervision by their respective governments in matters such as the environment, social responsibility, tort liability, health and safety, labor, the award of exploration and production contracts, the imposition of specific drilling and exploration obligations, taxation, foreign currency controls, price controls, export and import restrictions, capital expenditures and required divestments. In some countries in which we operate, such as Colombia, we are required to pay a percentage of our expected production to the government as royalties. See "Item 4. Information on the Company—B. Business Overview—Industry and regulatory framework—Colombia" and see Note 33.1 to our Consolidated Financial Statements.

For example, in Brazil there is potential liability for personal injury, property damage and other types of damages. Failure to comply with these laws and regulations also may result in the suspension or termination of operations or our being subjected to administrative, civil, and criminal penalties, which could have a material adverse effect on our financial condition and expected results of operations. We expect to also operate in a consortium in some of our concessions, which, under the Brazilian Petroleum Law, establishes joint and strict liability among consortium members, and failure to maintain the appropriate licenses may result in fines from the ANP, ranging from R$5 thousand to R$500 million. In addition, there is a contractual requirement in Brazilian concession agreements regarding local content, which has become a significant issue for oil and natural gas companies operating in Brazil given the penalties related with breaches thereof. The local content requirement will also apply to the production sharing contract regime. See "Item 4. Information on the Company—B. Business Overview—Our operations—Operations in Brazil."

Significant expenditures may be required to ensure our compliance with governmental regulations related to, among other things, licenses for drilling operations, environmental matters, drilling bonds, reports concerning operations, the spacing of wells, unitization of oil and natural gas accumulations, local content policy and taxation.

Colombia has experienced and continues to experience internal security issues that have had or could have a negative effect on the Colombian economy.

Despite the demobilization and disarmament that occurred because of the 2016 peace agreement, factors of instability persist in the territory, such as the presence of the Revolutionary Armed Forces of Colombia (FARC), the National Liberation Army (ELN) dissident forces and other illegal armed groups that seek to control drug trafficking and other illegal activities. The current government's intention to solidify peace agreements with all criminal elements may cause an escalation of violent incidents, damage to infrastructure and social mobilizations that may have adverse effects on the country's economy.

ELN has targeted crude oil pipelines in Colombia, including the Caño Limón-Coveñas pipeline, and other related infrastructure, disrupting the activities of certain oil and natural gas companies and resulting in unscheduled shutdowns of transportation systems. These activities, their possible escalation and the effects associated with them have had and may have in the future a negative impact on the Colombian economy or on our business, which may affect our employees or assets.

FARC has also historically attacked oil and gas infrastructure, bombing pipelines or attacking transport carrying oil and forcing drivers to spill it; these acts were committed by the 48th FARC battalion in Putumayo and our area of operations. For instance, in 2014, the content of 9 trucks of Vetra were spilled closed to Puerto Asis, Putumayo. Furthermore, these issues are under investigation by the special peace jurisdiction court since 2022.

Our operations in Colombia are subject to security and human rights risks.

Our operations can be affected by security related issues that may cause a halt or delay in production and exploration. The nature and magnitude of the risk may differ according to the area where operations are carried out. For example, our operations in the departments of Casanare and Meta may be affected by civil disturbances, including blockades. In the department of Putumayo the primary risk is the presence of illegal armed groups which control drug production and trafficking, and this situation can increase the perception of security risks, though the exact level of security risk depends on, among other factors, the location of the blocks and the time of crop production. Nevertheless, security risk assessments are developed on a yearly basis, and specific security related issues are constantly monitored. Moreover, since June 2022, we have strengthened our human rights and security risk management processes with our security contractors. As of December 2022, all our security contractors underwent training in security, human rights, and the voluntary principles (as determined by the United Nations Voluntary Principles on Security and Human Rights initiative).

While we remain committed to strengthening our security processes and protocols, there is no guarantee that incidents of such nature will not occur in the future. For example, in 2021 and 2022, our supply chain in the Llanos and Putumayo Basins was affected by a series of extensive protests and demonstrations across Colombia that included road blockades, which resulted in temporary production curtailments.

We have also identified potential risks to our operations, neighboring communities, employees, and contractors and service providers, due to the presence of land mines around several of our blocks in Putumayo. The land mines around this area were primarily used by FARC to attack public security forces, but other illegal armed groups in the area, including FARC dissidents, have also been known to place land mines to attack public security forces or use them against their enemies in the fight for drug trafficking and production.

In addition, our operations may be impacted by our adherence to national laws as well as all international human rights treaties ratified by the countries where we operate. As part of our commitment to respect human rights and engage in an open, respectful, and transparent manner with all our stakeholders, we always strive to resolve all issues with government authorities, especially following their lead with respect to guaranteeing human rights, through discussion and communication, which may result in delays to the advancement of our projects.

We expect that a limited number of financial institutions in the countries in which we operate, as well as some institutions located in the United States, will hold all or most of our cash.

We expect that a limited number of financial institutions in the countries in which we operate, as well as some institutions located in the United States, will hold all or most of our cash. Depending on our cash balance in any of our accounts at any given point in time, our balances may not be covered by government-backed deposit insurance programs in the event of default or failure of any bank with which we maintain a commercial relationship. The occurrence of any default or failure of any of the banks in which we have deposits could have a material adverse effect on our business, financial condition, results of operations and cash flows. For example, with regards to our accounts in the United States, while the U.S. Federal Deposit Insurance Corporation provides deposit insurance of US$250,000 per depositor, per insured bank, the amounts that we have in deposits in U.S. banks far exceed that insurance amount. Therefore, if the U.S. government does not impose measures to protect depositors in the event a bank in which our funds are held fails, we may lose all or a substantial portion of our deposits.

As of December 31, 2022, we maintained 75% of our cash at bank and other financial assets in top tier, A1 or higher rated banks. See Note 25.1 to our Consolidated Financial Statements.

Risks relating to our common shares

An active, liquid, and orderly trading market for our common shares may not develop and the price of our stock may be volatile, which could limit your ability to sell our common shares.

Our common shares began to trade on the New York Stock Exchange (the "NYSE") on February 7, 2014, and as a result have a limited trading history. We cannot predict the extent to which investor interest in our company will maintain an active trading market on the NYSE, or how liquid that market will be in the future.

The market price of our common shares may be volatile and may be influenced by many factors, some of which are beyond our control, including:

- our operating and financial performance and identified potential drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per common share, net income and revenues;
- changes in revenue or earnings estimates or publication of reports by equity research analysts;
- fluctuations in the price of oil or gas;
- speculation in the press or investment community;
- sales of our common shares by us or our shareholders, or the perception that such sales may occur;
- involvement in litigation;
- changes in personnel;
- announcements by the company;
- domestic and international economic, legal and regulatory factors unrelated to our performance;
- variations in our quarterly operating results;
- volatility in our industry, the industries of our customers and the global securities markets;
- changes in our dividend policy;
- risks relating to our business and industry, including those discussed above;
- strategic actions by us or our competitors;
- actual or expected changes in our growth rates or our competitors' growth rates;
- investor perception of us, the industry in which we operate, the investment opportunity associated with our common shares and our future performance;
- adverse media reports about us or our directors and officers;

- addition or departure of our executive officers;
- change in coverage of our company by securities analysts;
- trading volume of our common shares;
- future issuances of our common shares or other securities;
- terrorist acts; or
- the release or expiration of transfer restrictions on our outstanding common shares.

Any decision to pay dividends in the future, and the amount of any distributions, is at the discretion of our board of directors, and will depend on many factors, such as our results of operations, financial condition, cash requirements, prospects and other factors.

On November 6, 2019, our board of directors declared the initiation of a quarterly cash dividend of US$0.0413 per share. The first one was paid on December 10, 2019 and the second one was paid on April 8, 2020. After that, on April 20, 2020, we declared the temporary suspension of quarterly cash dividends and share buybacks as part of our revised work program for 2020 to help address the decline in oil prices.

On November 4, 2020, we resumed our dividend distributions by declaring an extraordinary cash dividend and a quarterly cash dividend (both dividends of $0.0206 per share), which were paid on December 9, 2020. On April 13, 2021, and May 28, 2021, we paid dividends of US$0.0205 per share. On August 31, 2021, and December 7, 2021, we paid dividends of US$0.041 per share. On March 31, 2022, and June 10, 2022, we paid dividends of US$0.082 per share and, on September 8, 2022, and December 7, 2022, we paid dividends of US$0.127 per share.

On March 8, 2023, our board of directors declared a cash dividend of US$0.13 per share payable on March 31, 2023.

Due to losses resulting from the oil price decline in previous years, accumulated losses amount to US$81.1 million as of December 31, 2022.

We are subject to Bermuda legal constraints that may affect our ability to pay dividends on our common shares and make other payments. Under the Companies Act, 1981 (as amended) of Bermuda (the "Companies Act"), we may not declare or pay a dividend or make a distribution out of contributed surplus, if there are reasonable grounds for believing that (i) we are, or would after the payment be, unable to pay our liabilities as they become due; or (ii) that the realizable value of our assets would thereby be less than our liabilities. We are also subject to contractual restrictions under certain of our indebtedness. "Contributed surplus" is defined for purposes of section 54 of the Companies Act to include the proceeds arising from donated shares, credits resulting from the redemption or conversion of shares at less than the amount set up as nominal capital and donations of cash and other assets to the company.

We are a holding company and our only material assets are our equity interests in our operating subsidiaries and our other investments; as a result, our principal source of revenue and cash flow is distributions from our subsidiaries; our subsidiaries may be limited by law and by contract in making distributions to us.

As a holding company, our only material assets are our cash on hand, the equity interests in our subsidiaries and other investments. Our principal source of revenue and cash flow is distributions from our subsidiaries. Thus, our ability to service our debt, finance acquisitions and pay dividends to our stockholders in the future is dependent on the ability of our subsidiaries to generate sufficient net income and cash flows to make upstream cash distributions to us. Our subsidiaries are and will be separate legal entities, and although they may be wholly-owned or controlled by us, they have no obligation to make any funds available to us, whether in the form of loans, dividends, distributions or otherwise. The ability of our subsidiaries to distribute cash to us will also be subject to, among other things, restrictions that are contained in our subsidiaries' financing and joint operations agreements, availability of sufficient funds in such subsidiaries and applicable state laws and regulatory restrictions. Claims of creditors of our subsidiaries generally will have priority as to the assets of such subsidiaries over our claims and claims of our creditors and stockholders. To the extent the ability of our subsidiaries to distribute dividends or other payments to us could be limited in any way, our ability to grow, pursue business opportunities or make acquisitions that could be beneficial to our businesses, or otherwise fund and conduct our business could be materially limited.

We may not be able to fully control the operations and the assets of our joint operations and we may not be able to make major decisions or take timely actions with respect to our joint operations unless our joint operation partners agree. We may, in the future, enter into joint operations agreements imposing additional restrictions on our ability to pay dividends.

Sales of substantial amounts of our common shares in the public market, or the perception that these sales may occur, could cause the market price of our common shares to decline.

We may issue additional common shares or convertible securities in the future, for example, to finance potential acquisitions of assets, which we intend to continue to pursue. Sales of substantial amounts of our common shares in the public market, or the perception that these sales may occur, could cause the market price of our common shares to decline. This could also impair our ability to raise additional capital through the sale of our equity securities. Under our memorandum of association, we are authorized to issue up to 5,171,949,000 common shares, of which 57,621,998 common shares were outstanding as of December 31, 2022. We cannot predict the size of future issuances of our common shares or the effect, if any, that future sales and issuances of shares would have on the market price of our common shares.

Provisions of the Notes due 2027 could discourage an acquisition of us by a third party.

Certain provisions of the Notes due 2027 could make it more difficult or more expensive for a third party to acquire us or may even prevent a third party from acquiring us. For example, upon the occurrence of a change of control, holders of the Notes due 2027 will have the right, at their option, to require us to repurchase all of their notes at a purchase price equal to 101% of the principal amount thereof plus any accrued and unpaid interest (including any additional amounts, if any) to the date of purchase. By discouraging an acquisition of us by a third party, these provisions could have the effect of depriving the holders of our common shares of an opportunity to sell their common shares at a premium over prevailing market prices.

Certain shareholders have substantial influence over us and could limit your ability to influence the outcome of key transactions, including a change of control.

Certain members of our board of directors and our senior management held 17.4% of our outstanding common shares as of March 9, 2023, holding the shares either directly or through privately held funds. As a result, these shareholders, if acting together, would be able to influence matters requiring approval by our shareholders, including the election of directors and the approval of amalgamations, mergers, or other extraordinary transactions. They may also have interests that differ from yours and may vote in a way with which you disagree, and which may be adverse to your interests. The concentration of ownership may have the effect of delaying, preventing, or deterring a change of control of our company, could deprive our stockholders of an opportunity to receive a premium for their common shares as part of a sale of our company and might ultimately affect the market price of our common shares. See "Item 7. Major Shareholders and Related Party Transactions—A. Major shareholders" for a more detailed description of our share ownership.

Shareholder activism could cause us to incur significant expenses, hinder execution of our business strategy and impact our stock price.

Shareholder activism has been increasing generally and in the energy industry specifically. Investors may attempt to effect changes to our business or governance, such as with respect to climate change or otherwise, by means such as shareholder proposals, public campaigns, proxy solicitations or other means. Such actions could adversely impact us by distracting the Board and employees from core business operations, increasing advisory fees and related costs, interfering with our ability to successfully execute on strategic transactions and plans and provoking perceived uncertainty about the future direction of the business.

As a foreign private issuer, we are subject to different U.S. securities laws and NYSE governance standards than domestic U.S. issuers. This may afford less protection to holders of our common shares, and you may not receive corporate and company information and disclosure that you are accustomed to receiving or in a manner in which you are accustomed to receiving it.

As a foreign private issuer, the rules governing the information that we disclose differ from those governing U.S. corporations pursuant to the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Although we intend to report quarterly financial results and report certain material events, we are not required to file quarterly reports on Form 10-Q or provide current reports on Form 8-K disclosing significant events within four days of their occurrence and our quarterly or current reports may contain less information than required under U.S. filings. In addition, we are exempt from the Section 14 proxy rules, and proxy statements that we distribute will not be subject to review by the SEC. Our exemption from Section 16 rules regarding sales of common shares by insiders means that you will have less data in this regard than shareholders of U.S. companies that are subject to the Exchange Act. As a result, you may not have all the data that you are accustomed to having when making investment decisions. For example, our officers, directors and principal shareholders are exempt from the reporting and "short-swing" profit recovery provisions of Section 16 of the Exchange Act and the rules thereunder with respect to their purchases and sales of our common shares. The periodic disclosure required of foreign private issuers is more limited than that required of domestic U.S. issuers and there may therefore be less publicly available information about us than is regularly published by or about U.S. public companies. See "Item 10. Additional Information—H. Documents on display."

As a foreign private issuer, we are exempt from complying with certain corporate governance requirements of the NYSE applicable to a U.S. issuer, including the requirement that a majority of our board of directors consist of independent directors as well as the requirement that shareholders approve any equity issuance by us which represents 20% or more of our outstanding common shares. As the corporate governance standards applicable to us are different than those applicable to domestic U.S. issuers, you may not have the same protections afforded under U.S. law and the NYSE rules as shareholders of companies that do not have such exemptions.

There are regulatory limitations on the ownership and transfer of our common shares which could result in the delay or denial of any transfers you might seek to make.

The permission of the Bermuda Monetary Authority is required, under the provisions of the Exchange Control Act 1972 and related regulations, for all issuances and transfers of shares (which includes our common shares) of Bermuda companies to or from a non-resident of Bermuda for exchange control purposes, other than in cases where the Bermuda Monetary Authority has granted a general permission. The Bermuda Monetary Authority, in its notice to the public dated June 1, 2005, has granted a general permission for the issue and subsequent transfer of any securities of a Bermuda company from and/or to a non-resident of Bermuda for exchange control purposes for so long as any "Equity Securities" of the company (which would include our common shares) are listed on an "Appointed Stock Exchange" (which would include the New York Stock Exchange). In granting the general permission the Bermuda Monetary Authority accepts no responsibility for our financial soundness or the correctness of any of the statements made or opinions expressed in this annual report. Any changes in the permission granted by the Bermuda Monetary Authority and related regulations could result in a delay or denial of any transfer of shares an investor might seek.

We are a Bermuda company, and it may be difficult for you to enforce judgments against us or against our directors and executive officers.

We are incorporated as an exempted company under the laws of Bermuda and our assets are substantially located in Colombia, Chile, Brazil and Ecuador. In addition, several of our directors and executive officers reside outside the United States and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult or impossible to effect service of process within the United States upon us, or to recover against us on judgments of U.S. courts, including judgments predicated upon the civil liability provisions of the U.S. federal securities laws. Further, no claim may be brought in Bermuda against us or our directors and officers in the first instance for violation of U.S. federal securities laws because these laws have no extraterritorial application under Bermuda law and do not have force of law in Bermuda. However, a Bermuda court may impose civil liability, including the possibility of monetary damages, on us or our directors and officers if the facts alleged in a complaint constitute or give rise to a cause of action under Bermuda law.

There is no treaty in force between the United States and Bermuda providing for the reciprocal recognition and enforcement of judgments in civil and commercial matters. However, the courts of Bermuda would recognize any final and conclusive monetary in personam judgement obtained in a U.S. court (other than a sum of money payable in respect of multiple damages, taxes or other charges of a like nature or in respect of a fine or other penalty) and would give a judgement based thereon provided that (i) the U.S. court that entered the judgment is recognized by the Bermuda court as having jurisdiction over us or our directors and officers, as determined by reference to Bermuda conflict of law rules, (ii) such court did not contravene the rules of natural justice of Bermuda, such judgment was not obtained by fraud, the enforcement of the judgment would not be contrary to the public policy of Bermuda, (iii) no new admissible evidence relevant to the action is submitted prior to the rendering of the judgment by the courts of Bermuda, and (iv) there is due compliance with the correct procedures under the laws of Bermuda.

In addition, and irrespective of jurisdictional issues, the Bermuda courts will not enforce a U.S. federal securities law that is either penal or contrary to Bermuda public policy. An action brought pursuant to a public or penal law, the purpose of which is the enforcement of a sanction, power or right at the instance of the state in its sovereign capacity, will not be entertained by a Bermuda court. Certain remedies available under the laws of U.S. jurisdictions, including certain remedies under U.S. federal securities laws, would not be available under Bermuda law or enforceable in a Bermuda court, as they would be contrary to Bermuda public policy.

The transfer of our common shares may be subject to capital gains taxes pursuant to indirect transfer rules in Colombia.

In August 2020, the Colombian government enacted Decree 1103 that regulates the indirect transfer tax established in article 90-3 of the Colombian Tax Code. Through this regulation, the transfer of shares and assets of entities located abroad are taxed in Colombia when such transaction represents a transfer of assets located in Colombia ("Colombian Assets"). Although certain conditions and exemptions apply, corporate reorganizations shall monitor this new regulation. As we indirectly own Colombian Assets, the indirect transfer rules would apply to transfers of our common shares provided certain conditions outside of our control are met. If such conditions were present and as a result the indirect transfer rules were to apply to sales of our common shares, such sales would be subject to indirect transfer tax on the capital gain realized in connection with such sales. For a description of the indirect transfer rules and the conditions of their application see "Item 10. Additional Information—E. Taxation—Colombian tax on transfers of shares."

Legislation enacted in Bermuda as to Economic Substance may affect our operations.

Pursuant to the Economic Substance Act 2018 (as amended) of Bermuda (the "ES Act") that came into force on January 1, 2019, a registered entity other than an entity which is resident for tax purposes in certain jurisdictions outside Bermuda ("non-resident entity") that carries on as a business any one or more of the "relevant activities" referred to in the ES Act must comply with economic substance requirements. The ES Act may require in-scope Bermuda entities which are engaged in such "relevant activities" to be directed and managed in Bermuda, have an adequate of qualified employees in Bermuda, incur an adequate level of annual expenditure in Bermuda, maintain physical offices and premises in Bermuda or perform core income-generating activities in Bermuda. The list of "relevant activities" includes carrying on any one or more of: banking, insurance, fund management, financing, leasing, headquarters, shipping, distribution and service center, intellectual property and holding entities.

The ES Act could affect how we operate our business, which could adversely affect our business, financial condition and results of operations. Although it is presently anticipated that the ES Act will have little material impact on us or our operations, as the legislation is new and remains subject to further clarification and interpretation, it is not currently possible to ascertain the precise impact of the ES Act on us.

ITEM 4. INFORMATION ON THE COMPANY

A. History and development of the company

General

We were incorporated as an exempted company pursuant to the laws of Bermuda in February 2006. We maintain a registered office in Bermuda at Clarendon House, 2 Church Street, Hamilton HM11, Bermuda. Our principal executive office is located at Street 94 N° 11-30, 8, 9, 8th floor, Bogotá, Colombia, telephone number +57 1 743 2337.

The SEC maintains an internet website that contains reports, proxy, information statements and other information about issuers, like us, that file electronically with the SEC. The address of that website is www.sec.gov. The Company's website address is www.geo-park.com. The information contained on, or that can be accessed through, the Company's website is not part of, and is not incorporated into, this annual report.

Our Company

We are a leading independent oil and natural gas exploration and production ("E&P") company with operations in Latin America. We operate in Colombia, Chile, Brazil and Ecuador. We are focused on Latin America because we believe it is one of the richest and most underexplored hydrocarbon regions globally, with less presence of independent E&P companies compared to the United States and Canada. In this region, much of the acreage has historically been controlled or owned by state-owned companies. We believe that these factors create an opportunity for smaller, more agile companies like us to build a long-term business.

We produced a net average of 38.6 mboepd during the year ended December 31, 2022, of which 87.4%, 6.1%, 3.9%, 0.4% and 2.2% were, respectively, in Colombia, Chile, Brazil, Argentina and Ecuador, and of which 90.7% was oil. As of December 31, 2022, according to the ANH, we were ranked as the second largest oil operator in Colombia, where we made the largest new oil field discovery in the last 20 years and we are the first private oil and gas operator in Chile. Since 2014, we have been partners with Petrobras in one of Brazil's largest producing gas fields. During 2019, we signed the final participation contracts to start our operations in Ecuador. In January 2020, we successfully closed the acquisition and initiated operational takeover and integration of Amerisur's assets in Colombia. In May 2022, we recorded our first oil sales in Ecuador due to the successful drilling campaign in the Perico Block.

A clear set of priorities and key values have driven our Company through a two-decade track record of growth, ESG performance and strong value delivery.

Meeting the energy needs of a growing population while contributing to the energy transition requires us to conduct best-in-class oil and gas exploration and operation, to manage our assets in the most ethical and sustainable way, and to continue creating long-term value for our shareholders and all our stakeholders.

We have defined our business model around five principal capabilities:

- Top-level oil and gas exploration capability, which is our ability, experience, methodology and creativity to find and develop oil and gas reserves in the subsurface, based on the best science, solid economics and ability to take the necessary managed risks.

- Safest, lowest cost and most efficient operation, which is our ability to work opportunely to be the safest, lowest-cost producer, with the necessary know-how to profitably drill, produce, transport, and sell our oil and gas, and the drive and creativity to find solutions, overcome obstacles, seize opportunities and achieve results.

- Cleanest and kindest hydrocarbons, which is our ability to minimize the impact of our projects on the environment, to make our operational footprint cleaner and smaller, and to be the neighbor and partner of choice by creating a mutually beneficial relationship with the local communities where we work.

- Consistent free cash flow and value delivery, which is our ability to create consistent stakeholder value through disciplined capital allocation, rigorous and comprehensive risk management, self-funded and flexible work programs, capital, and operating cost efficiency, maximizing the value of every barrel, expanding scale, protecting the balance sheet and returning tangible value to our shareholders.

- Commitment and culture, which is our ability to build a performance-driven and trust-based culture, based on our internal value system called Safety, Prosperity, Employees, Environment and Community Development ("SPEED"), that values and protects our communities, employees, environment, and shareholders to underpin and strengthen our long-term plan for success.

  We believe that our risk and capital management policies have enabled us to compile a geographically diverse portfolio of properties that balances exploration, development and production of oil and gas. These attributes have also allowed us to raise capital and to partner with premier international companies. Most importantly, we believe we have developed a distinctive culture within our organization that promotes and rewards trust, partnership, entrepreneurship and merit. Consistent with this approach, all of our employees are eligible to participate in our long-term incentive program, which is the Performance-Based Employee Long-Term Incentive Program. See "Item 6. Directors, Senior Management and Employees—B. Compensation—Employee Performance-Based and Long-Term Incentive Programs."

Based on our business model we have defined three priorities:

- Base business performance and delivery: continue to exert discipline in the capital allocation process to unlock the value in our organic opportunities to develop our reserves and in our exploration prospects.

- Discipline and profitable growth and scale: ability and initiative to assemble the right balance and portfolio of upstream assets, in the right hydrocarbon basins, in the right regions, with the right partners and at the right price – coupled with the vision and skills to transform and improve value above ground.

  - Energy transition and ESG focus: no issue is as relevant for the oil and gas industry as ensuring access to critical energy sources while curbing greenhouse gas emissions and limiting global warming. We reduce the emissions in our operations through powering our fields with renewable energy, further increasing energy efficiency and permanently improving our facilities and processes. Additionally, our SPEED program, which has been our guide for the past 20 years, follows ESG best practices.

History

We were founded in 2002. We are a leading independent oil and natural gas exploration and production ("E&P"), company with operations in Latin America. During 2022, we had operations in Colombia, Chile, Brazil, Argentina and Ecuador.

Our History can be summarized by our growth in each country and our performance in the capital markets:

Chile

In 2006, after demonstrating our technical expertise and committing to an exploration and development plan, we obtained a 100% operating working interest in the Fell Block from the Republic of Chile. Then, in 2011, ENAP awarded us the opportunity to obtain operating working interests in each of the Isla Norte, Flamenco and Campanario Blocks in Tierra del Fuego, Chile, which we refer to collectively as the Tierra del Fuego Blocks, and in 2012, jointly with ENAP, we entered into CEOPs with Chile for the exploration and exploitation of hydrocarbons within these blocks.

Colombia

In the first quarter of 2012, we moved into Colombia by acquiring three privately held E&P companies, that were later merged into GeoPark Colombia S.A.S. These acquisitions provided us with an attractive platform of reserves and resources in Colombia, including a 45% operated working interest in the Llanos 34 Block.

During 2019, jointly with Ecopetrol/Hocol, we acquired five low-cost, low-risk and high-potential exploration blocks in the Llanos Basin, surrounding the Llanos 34 Block, and we also executed an agreement with Parex to assume a 50% non-operated working interest in the Llanos 94 Block.

On January 16, 2020, we acquired the entire share capital of Amerisur, a company previously listed on the Alternative Investment Market ("AIM") of the London Stock Exchange. The principal activities of Amerisur were exploration, development and production of oil and gas reserves in Latin America.

In 2022, we executed an agreement with Parex to assume a 50% non-operated working interest in the CPO-4-1 Block.

Brazil

Since 2013, we have participated in several Bid Rounds promoted by the Brazilian ANP. In 2014, we acquired a 10% non-operated working interest in the BCAM-40 Concession, which included an interest in the Manati Gas Field operated by Petrobras.

Ecuador

On May 22, 2019, we signed final participation contracts for the Espejo (GeoPark operated, 50% working interest) and Perico (GeoPark non-operated, 50% working interest) Blocks in Ecuador, which were awarded to GeoPark in the Intracampos Bid Round held in Quito, Ecuador, in April 2019. We assumed a commitment of carrying out 3D seismic in the Espejo Block and drilling four exploration wells in each block, which amounts to US$39 million in capital expenditures for our working interest, until June 2025.

In May 2022, we recorded our first oil sales in Ecuador due to the successful drilling campaign of three exploration wells in the Perico Block. During 2022, we completed the acquisition of 60 sq km of 3D seismic in the Espejo Block and we drilled and completed the first exploration well in the block, which resulted in discovery of oil, with testing activities currently underway.

Other Latin American countries

During our history as operators, we have also had operations in Argentina and Peru, and we have participated in bid rounds in Mexico. As of the date of this annual report, we do not have operations in these countries.

Funding

In February 2014, we commenced trading on the NYSE and raised US$98 million (before underwriting commissions and expenses), including the over-allotment option granted to and exercised by the underwriters, through the issuance of 13,999,700 common shares.

In September 2017, we issued US$425.0 million aggregate principal amount of 6.50% senior notes due 2024 (the "2024 Notes"). The net proceeds from the Notes were used by us (i) to fully repay senior secured notes due 2020 and to pay any related fees and expenses, including a call premium, and (ii) for general corporate purposes, including capital expenditures, such as the acquisition of Aguada Baguales, El Porvenir and Puesto Touquet blocks in the Neuquén Basin in Argentina and to repay existing indebtedness, including the Itaú loan.

In January 2020, we issued US$350.0 million aggregate principal amount of 5.5% senior notes due 2027 (the "2027 Notes"). The net proceeds from the Notes were used by us (i) to pay the total consideration for the acquisition of Amerisur and to pay related fees and expenses, and (ii) for general corporate purposes.

In April 2021, we executed a series of transactions that included a successful tender to purchase US$255.0 million of the 2024 Notes that was funded with a combination of cash in hand and a US$150.0 million new issuance from the reopening of the 2027 Notes. The issuance and the tender offer closed on April 23, 2021, and April 26, 2021, respectively.

The tender total consideration included the tender offer consideration of US$1,000 for each US$1,000 principal amount of the 2024 Notes plus the early tender payment of US$50 for each US$1,000 principal amount of the 2024 Notes. The tender also included a consent solicitation to align the covenants of the 2024 Notes to those of the 2027 Notes. The reopening of the 2027 Notes was priced above par at 101.875%, representing a yield to maturity of 5.117%. The debt issuance cost for this transaction amounted to US$2.0 million. The Notes are fully and unconditionally guaranteed jointly and severally by GeoPark Chile S.p.A. and GeoPark Colombia S.L.U.

Between March and July 2022, we continued our deleveraging process by repurchasing and cancelling with the trustee, a total nominal amount of US$102,876,000 of our 2024 Notes. Of this total amount, US$57,876,000 was repurchased in open market transactions at prices below the call option level and US$45,000,000 was redeemed at a redemption price stated in the indenture governing the 2024 Notes.

On June 17, 2022, we received requisite consents from holders of the 2027 Notes for certain amendments to the indenture governing the 2027 Notes. The amendments addressed the impact of adverse market conditions and related drop in the price of crude oil during 2020 on our results, which in turn negatively impacted the restricted payments builder basket, and increased and reset the general restricted payments basket in the indenture to provide us additional restricted payments capacity, giving us additional financial flexibility. Consequently, on June 27, 2022, we paid a consent fee equal to $10.00 per $1,000 to holders of the 2027 Notes that delivered their consents for the abovementioned amendments to the indenture governing the 2027 Notes.

On September 21, 2022, we fully redeemed our 2024 Notes by redeeming the remaining aggregate principal amount of US$67,124,000. Pursuant to the terms of the indenture governing the 2024 Notes, the 2024 Notes were redeemed at a redemption price equal to 101.625% of the principal amount of the 2024 Notes redeemed, plus accrued and unpaid interests.

Following the abovementioned transactions, we reduced our total indebtedness nominal amount by US$275.0 million by using the cash generated from our operations and improved our financial profile by extending our debt maturities.

B. Business Overview

We have grown our business through drilling, developing and producing oil and gas, winning new licenses and acquiring strategic assets and businesses. Since our inception, we have supported our growth through our prospect development efforts, drilling program, long-term strategic partnerships and alliances with key industry participants, accessing debt and equity capital markets, developing and retaining a technical team with vast experience and creating a successful track record of finding and producing oil and gas in Latin America. A key factor behind our success ratio is our experienced team of geologists, geophysicists and engineers, including professionals with specialized expertise in the geology of Colombia, Chile, Brazil, Argentina and Ecuador.

The following map shows the countries in which we have blocks with working and/or economic interests as of December 31, 2022. For information on our working interests in each of these blocks, see "—Our assets" below.

(1) Termination of the E&P contract was approved by the ANH and final liquidation is in process. See "—Our operations—Operations in Colombia".

(2) In process of relinquishment. See "—Our operations—Operations in Colombia" and "—Our operations—Operations in Argentina."

(3) As of the date of this annual report, suspension of the terms of the exploratory period and transfer of the investment commitment to another block is under negotiation.. See "—Our operations—Operations in Argentina."

The following table sets forth our net proved reserves and other data as of and for the year ended December 31, 2022.

	For the year ended December 31, 2022					
Country	Oil (mmbbl)	Gas (bcf)	Oil equivalent (mmboe)	% Oil	Revenues (in thousands of US$)	% of total revenues
Colombia	64.4	1.1	64.6	99.7 %	978,423	93.2 %
Chile	1.6	14.1	3.9	40.4 %	29,196	2.8 %
Brazil	0.0	9.4	1.6	0.5 %	19,873	1.9 %
Argentina	—	—	—		1,962	0.2 %
Ecuador	0.3	—	0.3	100.0 %	10,671	1.0 %
Other	—	—	—		9,454	0.9 %
Total	66.3	24.6	70.4	94.2 %	1,049,579	100.0 %

Our commitment to growth has translated into a compounded annual growth rate ("CAGR"), of 2% for production in the period from 2018 to 2022, as measured by boepd in the table below.

	For the year ended December 31,				
	2022	2021	2020	2019	2018
Average net production (mboepd)	38.6	37.6	40.2	40.0	36.0
% oil	91 %	86 %	87 %	86 %	85 %

The following table sets forth our production of oil and natural gas in the blocks in which we have a working and/or economic interest as of December 31, 2022.

	Average daily production For the year ended December 31, 2022					
	Colombia	Chile	Brazil	Argentina	Ecuador	Total
Oil production						
Total crude oil production (bopd)	33,640	441	21	80	848	35,029
Natural gas production						
Total natural gas production (mcf/day)	776	11,387	8,967	416	—	21,546
Oil and natural gas production						
Total oil and natural gas production (mboepd)	33,769	2,338	1,516	149	848	38,620

Our assets

We have a well-balanced portfolio of assets that includes working and/or economic interests in 38 hydrocarbon blocks, 37 of which are onshore blocks, including 9 in production as of December 31, 2022. Our assets give us access to more than 5.1 million gross exploratory and productive acres.

According to the D&M Reserves Report, as of December 31, 2022, the blocks in Colombia, Chile, Brazil and Ecuador in which we have a working interest had 70.4 mmboe of net proved reserves, with 91.7%, 5.6%, 2.2% and 0.5% of such net proved reserves located in Colombia, Chile, Brazil and Ecuador, respectively.

We produced a net average of 38.6 mboepd during the year ended December 31, 2022, of which 87.4%, 6.1%, 3.9%, 0.4% and 2.2%, were in Colombia, Chile, Brazil, Argentina and Ecuador, respectively, and of which 90.7% was oil.

Our strengths

We believe that we benefit from the following competitive strengths:

High quality and diversified asset base built through a successful track record of organic growth and acquisitions

Our assets include a diverse portfolio of oil and natural gas-producing reserves, operating infrastructure, operating licenses and valuable geological surveys in Latin America. Throughout our history, we have delivered continuous growth in our production, and our management team has been able to identify under-exploited assets and turn them into valuable, productive assets, and to allocate resources effectively based on prevailing conditions.

- Colombia. In 2012, we acquired assets in Colombia at attractive prices, which gave us access to exploratory and productive acres with many prospects. In the Llanos Basin, we pioneered a new play type combining structural and stratigraphic traps. As a result, in the Llanos 34 Block our average daily production has grown from 0 bopd at the time of acquisition to 25,657 bopd at our working interest, during the year ended December 31, 2022. During 2019, jointly with Ecopetrol/Hocol, we acquired five low-cost, low-risk and high potential exploration blocks in the Llanos Basin, surrounding the Llanos 34 Block, and we also executed an agreement with Parex to assume a 50% non-operated working interest in the Llanos 94 Block. On January 16, 2020, we acquired the entire share capital of Amerisur, which owned thirteen production, development and exploration blocks in Colombia and a cross-border oil pipeline from Colombia to Ecuador named Oleoducto Binacional Amerisur ("OBA"). In 2022, we executed an agreement with Parex to assume a 50% non-operated working interest in the CPO-4-1 Block.

- Chile. In 2002, we acquired a non-operating working interest in the Fell Block in Chile, which at the time had no material oil and gas production or reserves despite having been actively explored and drilled over the course of more than 50 years. Since 2006, when we became the operator of the Fell Block, we have performed active exploration and development drilling that resulted in multiple oil and gas discoveries.

- Brazil. Since 2013, we have participated in several Bid Rounds promoted by the Brazilian ANP and were awarded exploratory concessions. In 2014, we acquired Rio das Contas, which gave us a 10% working interest in the BCAM-40 Concession, including the shallow-depth offshore Manati Field in the Camamu-Almada Basin in the State of Bahia, which has consistently self-funded its operations. The Manati Field has provided up to 1.1% of total gas produced in Brazil.

- Ecuador. On May 22, 2019, we signed final participation contracts for the Espejo (GeoPark operated, 50% working interest) and Perico (GeoPark non-operated, 50% working interest) Blocks in Ecuador, which were awarded to GeoPark in the Intracampos Bid Round held in Quito, Ecuador in April 2019. In May 2022, we recorded our first oil sales in Ecuador due to the successful drilling campaign of three exploration wells in the Perico Block. During 2022, we completed the acquisition of 60 sq km of 3D seismic in the Espejo Block and we drilled and completed the first exploration well in the block, which resulted in discovery of oil, with testing activities currently underway.

Significant drilling inventory and resource potential from existing asset base

Our portfolio includes large land holdings in high-potential hydrocarbon basins and blocks with multiple drilling leads and prospects in different geological formations, which provide several attractive opportunities with varying levels of risk. Our drilling inventory and our development plans target locations that provide attractive economics and support a predictable production profile, as demonstrated by our expansions in Colombia.

Our geoscience team continues to identify new potential accumulations and expand our inventory of prospects and drilling opportunities.

Continue to grow a risk-balanced asset portfolio

We intend to continue to focus on maintaining a risk-balanced portfolio of assets, combining cash flow-generating assets with upside potential opportunities, and on increasing production and reserves through finding, developing and producing oil and gas reserves in the countries in which we operate. In general, when we enter a new country we look for a mix of three elements: (i) producing fields, or existing discoveries with near-term possibility of production, to generate cash flows; (ii) an inventory of adjacent low-risk prospects that can offer medium-term upside for steady growth; and (iii) a periphery of higher-risk projects which have a potential to generate significant upside in the long run.

For example, in Colombia, we acquired Amerisur to pursue a risk-balanced approach: one block had mainly proven production and reserves to provide us with a steady cash flow base, and the remaining blocks had highly prospective exploration licenses.

We believe this approach will allow us to sustain continuous and profitable growth and also participate in higher risk growth opportunities with upside potential. See "—Our operations."

Platform and Funding

We are focused on continued growth utilizing a disciplined capital structure and a conservative financial philosophy. Due to the volatile nature of commodity prices, expenditure discipline and a focus on disciplined capital structure are critical to our business. Our multi-country platform and asset portfolio is managed through our capital allocation methodology, which also allows us to quickly adapt and grow. Under this methodology, each country, has a local team running the business who recommends and advocates for the projects with which they want to move forward. The corporate team then ranks all of the projects based on economic, technical, environmental, social and corporate governance and strategic criteria, for the purpose of comparing projects. This also creates opportunities for improvements in the projects that can, in turn, improve their ranking. Finally, once the production and reserve growth targets are defined, the corporate team agrees on the amount of capital to be invested and allocates that capital to the highest value-adding projects. As an example, for the 2023 capital allocation process, over 325 projects were selected which comprise our 2023 work program, under the base capital program. Additionally, given the inherent oil price volatility, we design our work programs to be flexible, which means that they can be increased or decreased depending on the oil price scenario.

We have historically benefited from access to debt and equity capital markets and cash flows from operations, as well as other funding sources, which have provided us with funds to finance our organic growth and the pursuit of potential new opportunities.

In February 2014, we commenced trading on the NYSE and raised US$98 million (before underwriting commissions and expenses), including the over-allotment option granted to and exercised by the underwriters, through the issuance of 13,999,700 common shares.

In September 2017, we issued US$425.0 million aggregate principal amount of 6.50% senior notes due 2024 (the "2024 Notes"). The net proceeds from the Notes were used by us (i) to fully repay senior secured notes due 2020 and to pay any related fees and expenses, including a call premium, and (ii) for general corporate purposes, including capital expenditures, such as the acquisition of Aguada Baguales, El Porvenir and Puesto Touquet blocks in the Neuquén Basin in Argentina and to repay existing indebtedness, including the Itaú loan.

In January 2020, we issued US$350.0 million aggregate principal amount of 5.5% senior notes due 2027 (the "2027 Notes"). The net proceeds from the Notes were used by us (i) to pay the total consideration for the acquisition of Amerisur and to pay related fees and expenses, and (ii) for general corporate purposes.

In April 2021, we executed a series of transactions that included a successful tender to purchase US$255.0 million of the 2024 Notes that was funded with a combination of cash in hand and a US$150.0 million new issuance from the reopening of the 2027 Notes. The issuance and the tender offer closed on April 23, 2021, and April 26, 2021, respectively.

The tender total consideration included the tender offer consideration of US$1,000 for each US$1,000 principal amount of the 2024 Notes plus the early tender payment of US$50 for each US$1,000 principal amount of the 2024 Notes. The tender also included a consent solicitation to align the covenants of the 2024 Notes to those of the 2027 Notes. The reopening of the 2027 Notes was priced above par at 101.875%, representing a yield to maturity of 5.117%. The debt issuance cost for this transaction amounted to US$2.0 million. The Notes are fully and unconditionally guaranteed jointly and severally by GeoPark Chile S.p.A. and GeoPark Colombia S.L.U.

Between March and July 2022, we continued our deleveraging process by repurchasing and cancelling with the trustee, a total nominal amount of US$102,876,000 of our 2024 Notes. Of this total amount, US$57,876,000 was repurchased in open market transactions at prices below the call option level and US$45,000,000 was redeemed at a redemption price stated in the indenture governing the 2024 Notes.

On June 17, 2022, we received requisite consents from holders of the 2027 Notes for certain amendments to the indenture governing the 2027 Notes. The amendments addressed the impact of adverse market conditions and related drop in the price of crude oil during 2020 on our results, which in turn negatively impacted the restricted payments builder basket, and increased and reset the general restricted payments basket in the indenture to provide us additional restricted payments capacity, giving us additional financial flexibility. Consequently, on June 27, 2022, we paid a consent fee equal to $10.00 per $1,000 to holders of the 2027 Notes that delivered their consents for the abovementioned amendments to the indenture governing the 2027 Notes.

On September 21, 2022, we fully redeemed our 2024 Notes by redeeming the remaining aggregate principal amount of US$67,124,000. Pursuant to the terms of the indenture governing the 2024 Notes, the 2024 Notes were redeemed at a redemption price equal to 101.625% of the principal amount of the 2024 Notes redeemed, plus accrued and unpaid interests.

Following the abovementioned transactions, we reduced our total indebtedness nominal amount by US$275.0 million by using the cash generated from our operations and improved our financial profile by extending our debt maturities.

We generated US$467.5 million and US$216.8 million in cash from operations in the years ended December 31, 2022 and 2021, respectively, and had US$128.8 million and US$100.6 million of cash and cash equivalents as of December 31, 2022 and 2021, respectively.

As of December 31, 2022, we had US$497.6 million of total outstanding indebtedness which is scheduled to mature in 2027.

Strong cash flow

We benefit from a strong cash flow from operating activities. For the year ended December 31, 2022, cash flows from operating activities were US$467.5 million. Our cash flows from operating activities plays a significant role in funding our capital expenditures.

Maintain financial strength

We seek to maintain a prudent and sustainable capital structure and a strong financial position to allow us to maximize the development of our assets and capitalize on business opportunities as they arise. We intend to remain financially disciplined by limiting substantially all our debt incurrence to identified projects with repayment sources. We expect to continue benefiting from diverse funding sources such as our partners and customers in addition to the international capital markets.

Our cash flow generation is complemented by our financial hedging program. Since October 2016, we have entered into derivative financial instruments to manage our exposure to oil price risk. The purpose of our hedging strategy is to establish minimum oil prices to secure a stable cash flow and the execution of our work program. For more information regarding our financial hedging program please see Note 8 to our Consolidated Financial Statements.

Since December 2018, we decided to manage our future exposure to local currency fluctuation with respect to income tax balances in Colombia. Consequently, from time to time, we entered into derivative financial instruments in order to anticipate any currency fluctuation with respect to income taxes to be paid during the first half of the following year. No currency risk management contracts were engaged during the years ended December 31, 2022 and 2021. In January 2023, we entered into derivative financial instruments (zero-premium collars) with local banks in Colombia, for an amount equivalent to US$38.0 million in order to anticipate any currency fluctuation with respect to a portion of the estimated income taxes to be paid in April and June 2023.

In relation to the cash consideration payable for the acquisition of Amerisur, we were exposed to fluctuations of the British pound sterling as of December 31, 2019. Consequently, we decided to manage this exposure by entering into a deal-contingent forward with a British bank, in order to anticipate any currency fluctuation.

We believe that by maintaining a disciplined capital structure and a conservative financial philosophy, including limiting our debt incurrence to specified projects with repayment sources and our use of financial hedges, we are positioned to maintain sufficient liquidity and remain flexible in volatile commodity price environments. Our financial flexibility also gives us the ability to pursue new opportunities through future potential acquisitions.

Pursue strategic acquisitions in Latin America

We have historically benefited from, and intend to continue to grow through, strategic acquisitions in Latin America. These acquisitions have provided us with additional attractive platforms in the region. Our Colombian acquisitions, for example, highlight our ability to identify and execute on attractive growth opportunities, as we have grown to become the second largest operator in Colombia. We acquired our interest in the Llanos 34 Block in the first quarter of 2012 for US$30 million and have achieved 1P reserve PV-10 of US$1.1 billion as of December 31, 2022. Our enhanced regional portfolio, including investment-grade countries and strong partnerships, position us as a regional consolidator. We intend to continue to grow through strategic acquisitions in other countries in Latin America, which we may consider from time to time. Our acquisition strategy is aimed at maintaining a balanced portfolio of lower-risk cash flow-generating properties and assets that have upside potential, keeping a balanced mix of oil and gas-producing assets (though we expect to remain weighted towards oil) and focusing on both assets and corporate targets.

On January 16, 2020, we acquired the entire share capital of Amerisur, a company listed on the Alternative Investment Market ("AIM") of the London Stock Exchange. The principal activities of Amerisur were exploration, development and production for oil and gas reserves in Latin America. Amerisur owned thirteen production, development and exploration blocks in Colombia (twelve operated blocks in the Putumayo Basin and one non-operated block in the Llanos Basin) and a cross-border oil pipeline from Colombia to Ecuador named Oleoducto Binacional Amerisur ("OBA").

Maintain a high degree of operatorship to control production costs

As of the date of this annual report, we are and intend to continue to be the operator of a majority of the blocks and concessions in which we have working interests. Operating the majority of our blocks and concessions gives us the flexibility to allocate our capital and resources opportunistically and efficiently within a diversified asset portfolio. We believe that this strategy has allowed, and will continue to allow us, to leverage our unique culture, focused on excellence, and our talented technical, operating and management teams. For example, as commodity prices were projected to decline throughout 2020, on March 19, 2020, we announced a decision to shift our development plan primarily to our operations in the Llanos 34 Block to focus on the Llanos Basin, which had demonstrated strong returns on capital. Our operating team reacted quickly to pivot our operations that were unburdened by drilling obligations and worked with our service partners to coordinate a smooth and efficient transition to a new plan. Since then, we were able to control production costs, as exemplified by our average operating costs for the Llanos 34 Block, which were US$6.4 per boe for the year ended December 31, 2022.

Long-term strategic partnerships and strong strategic relationships provide us with additional funding flexibility to pursue further acquisitions

We benefit from a number of strong partnerships and relationships. In Chile, we believe we have strong long-term commercial relationships with Methanex and ENAP, and in Colombia, we believe we have developed a strong relationship with Ecopetrol, the Colombian state-owned oil and gas company. In Brazil, we believe we will continue to derive benefits from the long-term relationship with Petrobras.

In February 2018, we announced the formation of a new long-term strategic partnership to jointly acquire, invest in, and create value from upstream oil and gas projects with the objective of building a large-scale, economically-profitable and risk-balanced portfolio of assets and operations across Latin America with ONGC Videsh, the wholly-owned subsidiary and international arm of Oil and Natural Gas Corporation Limited, India's national oil company.

Maintain our commitment to environmental, safety, human rights and social responsibility

An important component of our business strategy is our corporate approach and commitment to our safety, environmental and social responsibilities, which is embodied in decisions that are framed by our safety, environmental and social responsibility internal policies and aligned with international standards. We see this as a fundamental element in securing business initiatives for long-term growth. Our commitment to sustainable development has allowed us to generate positive impacts in the territories in which we operate, with important contributions to the protection of biodiversity and the environment, as well as to the wellbeing and reduction of multidimensional poverty in neighboring communities. We maintain a social license to operate, based on the construction and maintenance of mutually beneficial relationships with local communities, the return of value as allies for their social and economic development, the respect for their human rights and the care and preservation of the environment.

Our internal value system is called Safety, Prosperity, Employees, Environment and Community Development ("SPEED"). Our SPEED program was developed in accordance with several international quality standards, including ISO 14001 (for environmental management issues), ISO 45001 (for occupational health and safety management issues), ISO 26000 (for social responsibility and workers' rights issues), IFC guidelines for social and environmental performance, and guidelines from associations including IOGP, IPIECA, IADC and ARPEL. See "—Health, safety and environmental matters."

During 2016, we began the ISO 14001 certifying process through programs related to the efficient use of natural resources and compliance with environmental regulation. We have also provided training to our staff and the communities in which we operate with respect to these matters.

In August 2017, we obtained the ISO 14001:2015 certification for our environmental management process for the design, construction, operation, maintenance, modernization, and dismantlement of GeoPark Colombia S.A.S.'s facilities, and the performance of exploration and oil and gas production activities in the Llanos 34 and VIM-3 blocks with a commitment to continuously improve our processes. We obtained the ISO 14001:2015 re-certification in 2018 and in 2020 the certification was renewed and extended until August 2023.

Since 2017, GeoPark has certified the greenhouse gas inventory of its operations in Scopes 1 and 2 in Colombia, through the NTC-ISO 14064-3:2006 standard of the Colombian Institute of Technical Standards and Certification (ICONTEC). GeoPark was the second private company to get this certification in Colombia, allowing us to draw a roadmap to reduce our emissions of greenhouse gases and help the country meet the commitment it took on at the 2015 United Nations Climate Change Conference. During 2022 and as part of this roadmap, we connected our Llanos 34 Block to the national electrical grid of Colombia and to a 10MW dedicated solar farm, both of which help reduce the block's emissions.

In 2018, the Colombian government granted GeoPark the "Best Social Practices in the Energy Industry" award for our good neighbor social conflict prevention program. GeoPark's model for community engagement was chosen out of 107 different initiatives by a panel composed of representatives from the Ministry of Mines and Energy, the National Hydrocarbons Agency and the United Nations Development Program. In 2019, we won the "Best Social Practices in the Energy Industry" award for the second year in a row, along with the "Best Socio-Laboral Practices" award for our "Juntos Sumamos" program. In 2021, we again won the "Best Social Practices in the Energy Industry" award for our "Sustainable Housing" program, which improves the living conditions and well-being of our neighbors in Casanare and Putumayo. The jury was composed of public sector members and representatives from academic and multilateral organizations. The award was determined based on the impact of each initiative, its sustainability efforts, innovation, and relation to the 2030 agenda.

In 2022, the national government, through its department for social prosperity, once again recognized our "Sustainable Housing" program among the 24 most important public, private and international cooperation programs in terms of overcoming poverty in Colombia. The homes of more than 2,000 families that are neighbors to our areas of operation in the country have been benefitted by this program, which we have been carrying out since 2013 in alliance with the 'Minuto de Dios' corporation.

Since 2021, we have participated in the private social investment index, an independent syndicated study conducted by Jaime Arteaga y Asociados (JA&A), which aims to measure the effort of the private sector to improve the living conditions of communities and/or population groups based on their voluntary decision to invest in social and environmental projects. In 2022, we participated along with the 150 largest companies in Colombia, obtaining special recognition for best performance in the "Focusing" component associated with the implementation of social and environmental investment initiatives in the most vulnerable areas and populations of the country.

In spite of physical distancing due to the COVID-19 pandemic, in 2021 we strove to maintain in permanent contact with the local communities in which we operate, contributing to food security for vulnerable households and supporting local and national authorities' efforts to halt the spread of the virus.

In 2019, we joined the Equipares gender equality certification program, an initiative of the Colombian government and the United Nations Development Program (UNDP) focused on achieving parity in the workplace. In 2020, we created a standing company-wide committee to implement action plans that encourage and sustain the values of equity, inclusion, and diversity. In 2020, we reported for the first time our gender equality metrics using the Bloomberg Gender Reporting Framework. In 2021 we achieved the Equipares Silver Seal, after the Colombian Institute of Technical Standards and Certification (ICONTEC) gave a 91/100 rating to our SGIG (Gender Equality Management System).

In January 2023, GeoPark was included for a second year in a row in the Bloomberg Gender-Equality Index, including companies with best-in-class gender-related practices and policies.

In 2022, we reported our SPEED and Environment, Social and Governance metrics according to the Global Reporting Initiative (GRI) standards as well as the sustainability reporting guide of the Global Oil and Gas Association for Advancing Environmental and Social Performance (IPIECA, 2020) and selected metrics of the Sustainability Accounting Standards Board (SASB, 2018).

Our 2021 SPEED and ESG report addresses the following identified matters: safety and health management, supply chain management, compliance, employee development and training, integrated water resources management, energy efficiency, emissions management, biodiversity protection, social risk assessment, and engagement with indigenous communities.

In 2022, our rating in the MSCI ESG Ratings assessment was upgraded from BBB in 2021 to A, with significant progress as compared to all other oil and gas, exploration, and production companies in the MSCI world index. The two key areas of major improvement were corporate governance and greenhouse gas emissions reduction. MSCI ranked the company in the highest range of scores relative to its global peers in corporate governance and as having "strong initiatives" in emissions. Health and safety and communities were also notable improvements.

In 2022, we submitted the Carbon Disclosure Project's (CDP) Climate Change questionnaire for the first time and obtained a C rating (awareness). We will continue to participate in this disclosure initiative and intend to also submit the CDP's Water Security questionnaire.

Our approach on human rights seeks to conduct business in a way that is consistent with the UN Guiding Principles on Business and Human Rights (the "UN Guiding Principles"), the ten UN Global Compact Principles and the Voluntary Principles on Security and Human Rights. Our commitment to these standards is reflected in our SPEED program, as well as in all our policies and procedures. Human rights aspects are integrated into internal management processes, tools, communications, contracts, and trainings.

We have a grievance mechanism in place for all our blocks and operations in Colombia, which is aligned with the UN Guiding Principles (UNGP) on Business and Human Rights, meaning it is accessible, legitimate, aligned with judicial and non-judicial grievance mechanisms, based on dialogue and participation, and predictable, to name a few of the eleven principles established in the UNGP. Having open, accessible, transparent, and respectful communication with all our stakeholders is crucial to respecting their human rights to information and participation. Our grievance mechanism, "Cuéntame" ("Tell me" in English), is one of our most important tools to engage with communities, contractors and service providers, and our employees on the ground, and this is especially true because it is easily accessible to all through all our social engagement employees, email, several mobile and Whatsapp numbers, and an office in the biggest city close to our operations. Furthermore, if any stakeholder approaches our doors, they will be informed about the mechanism and will be able to present a grievance, complaint or question immediately. To further align and strengthen our grievance mechanism with the highest standards on human rights, in 2022, we worked with a reputable NGO in Colombia called "Fundación Ideas para la Paz" to assess "Cuéntame" against the UNGP, the OECD Guidance, the International Financial Corporation and the World Bank standards. We were ranked as having best practices (meaning a complete level of implementation) in one of the UNGP, as having high level of progress and implementation in eight of the UNGP, and as having progress with an opportunity to improve in two of the UNGP. As part of the results, we have implemented a plan to close some of the gaps identified, for example by increasing the number of forums and meetings to communicate and raise awareness of the existence of the grievance mechanism, as well as providing stakeholders the opportunity to give feedback on the mechanism's operation, effectiveness, responses, among others.

In October 2021, GeoPark, the United Nations Development Program, and the Governments of Colombia and Chile received a communication from several United Nations Special Rapporteurs, requesting clarification on alleged negative human rights impacts in our Putumayo operation and information about our human rights policies and procedures. GeoPark and all other parties provided their respective responses to the information requests in the Special Rapporteurs' communication, and no further questions or issues have been raised by the United Nations High Commissioner on Human Rights or the Special Rapporteurs. Given the passage of time since our response in December 2021, we do not expect any further communications with respect to this matter. Furthermore, since our meeting with the Latin American Representative of United Nations Group on Business and Human Rights in February 2022, we have established a two-way communication with the organization, to further contribute towards the implementation of business and human rights.

Transparency, ethics and anti-corruption

Transparency is a cornerstone of good governance and it is embodied in our corporate values. Transparency allows business to prosper in a predictable and competitive environment. We believe that doing business in an ethical and transparent manner is a prerequisite for sustainable business. We have zero-tolerance policy towards all forms of corruption. This policy is embedded across our Company through our corporate values, our Code of Conduct (Our Code), and our Compliance Program. They prohibit all forms of corruption and bribery and reflects our values and our commitment to high ethical standards in business activities; they apply to all our employees, board members and third parties.

Our Compliance Program aims to support and promote an ethics culture, as well as create and establish commitments and procedures that ensure internal and external regulatory compliance and anti-corruption matters. Program execution and implementation is the responsibility of our Compliance Department, an independent area specialized in guaranteeing the fulfilment of our commitments and which is directed and coordinated by the Compliance Director, who reports directly to the Chief Executive Officer and the Audit Committee. The program is based on three pillars:

- Prevention: Ethics-Based Culture, including Tone from the Top matters, Training & Awareness and Ethic Line management

- Detection: Risk Assessment and Advisory, including Policies & Procedures assurance, Laws & Regulations compliance and Risk Assessment management

- Monitoring: Monitor and Oversight, including On-Going Monitoring, Due Diligence Third Parties and Regulations Oversight

Since 2018, we have actively participated in the Colombian Extractive Industries Transparency Initiative (EITI) and contributed data to the country's annual EITI report. During 2022, GeoPark joined the Business Ethics Leadership Alliance (BELA) as part of its efforts to continue strengthening its ethical culture. BELA is a platform of more than 375 companies in 60 industries recognized worldwide for their ethics and compliance leadership.

Highly committed founding shareholder and technical and management teams with proven industry expertise and technically-driven culture

Management and operating teams have significant experience in the oil and gas industry and a proven technical and commercial performance record in onshore fields, as well as complex projects in Latin America and around the world, including expertise in identifying acquisition and expansion opportunities. Moreover, we differentiate ourselves from other E&P companies through our technically-driven culture, which fosters innovation, creativity and timely execution. Our geoscientists, geophysicists and engineers are pivotal to the success of our business strategy, and we have created an environment and supplied the resources that enable our technical team to focus its knowledge, skills and experience on finding and developing oil and gas fields.

In addition, we strive to provide a safe and motivating workplace for employees in order to attract, protect, retain and train a quality team in the competitive marketplace for capable energy professionals.

One of our founding shareholders and current Vice Chair of the Board, Mr. James F. Park, has been involved in E&P projects in Latin America since 1978. He has been closely involved in grass-roots exploration activities, drilling and production operations, surface and pipeline construction, legal and regulatory issues, crude oil marketing and transportation and capital raising for the industry. As of March 9, 2023, Mr. Park held 15.2% of our outstanding common shares.

Our management and operating team have an average experience in the energy industry of more than 25 years in companies such as Chevron, ENAP, Petrobras, Pluspetrol, San Jorge, Total and YPF, among others. Throughout our history, our management and operating team has had success in unlocking unexploited value from previously underdeveloped assets.

In addition, as of March 9, 2023, our executive directors and key management (excluding Mr. James F. Park) owned 1.5% of our outstanding common shares, aligning their interests with those of our shareholders and helping retain the talent we need to continue to support our business strategy. See "Item 6. Directors, Senior Management and Employees—B. Compensation." One of our founding shareholders is also involved in our daily operations and strategy.

Technically-driven culture and capitalization of local knowledge

We intend to continue to pursue strategies that maximize value. For this purpose, we intend to continue expanding our technical teams and to foster a culture that rewards talent according to results. For example, we have been able to maintain the technical teams we inherited through our Colombian and Brazilian acquisitions. We believe local technical and professional knowledge is key to operational and long-term success and intend to continue to secure local talent as we grow our business in different locations.

Innovation

At GeoPark, we understand innovation as a way to strengthen our work culture that seeks, continuously, improvements in its processes, with the aim of reducing costs, increasing production, mitigating risks and managing information more efficiently. We have the conviction that a culture of innovation is one of the fundamental pillars to ensure the sustainability of the company over time. Through proactive innovation we seek to maximize positive impacts on productivity, effective decision-making based on reliable, relevant and timely information, the strengthening of teamwork, the installation of leadership skills, and the consolidation of a culture that promotes creativity and generation of ideas.

With the projects implemented from the innovation program, we generate real impact and potential future benefits in the internal economy, the environment and the acquisition of new skills in the company. Innovation contributes to the improvement of conditions that positively impact the communities where we operate and to the strengthening of our ability to adapt more quickly to an ever-changing environment.

During 2022, we monitored different innovation projects that were identified in workshops, managing to install an innovation culture that was expanding in various areas. The company continues to successfully incorporate digital capabilities like Artificial Intelligence, Machine Learning, Internet of Things, Big Data, Automation and Cloud Computing. During this year, the company implemented many innovation initiatives involving top partners like Microsoft, Google, Halliburton, Cisco, SAP, Indra among others. The following are some of the projects that have been part of the innovation journey. Some of them are still in progress:

- Production testing and data management: optimization of data measurement in the wells.
- Well production optimization: data management platform with self-service visualizations, trending, and analytics.
- Digital drilling: We automated the drilling platforms using sophisticated technology with partners such as Halliburton, aimed at increasing the rate of penetration and reducing costs focused on non-production time and unplanned events based on information from the drillers. During our drilling operations, our platform helps the operation make quicker, smarter decisions to stay on plan and achieve predictable results consistently.
- Work Over-Well Service: artificial lift systems aiming to optimize the extraction processes using artificial intelligence.
- Sludge management in the Tigana field in Llanos 34 Block (Colombia).
- Energy optimization: energy demand reduction boosting a savings culture.
- ESP failure prediction: During 2021, we successfully created and implemented a model using artificial intelligence and machine learning to predict failures of the electro submersible pump platforms. We continued using this technology during 2022.
- Water surface processes: optimization of the surface production process to simplify the operation.
- Domestic wastewater treatment.

Several projects were implemented in all areas of the organization involving people, processes and technology. We are constantly looking for opportunities to innovate by driving enterprise productivity, employee collaboration, communication and decision-making by leveraging technology.

We continue to work to expand the reach of this culture of innovation to more people in the Company. In 2023, we plan to hold a new workshop to capture ideas that allow improvements in core and support areas.

For a more in-depth discussion of our 2022 results, liquidity and its capital resources, please see “Item 5—Operating and Financial Review and Prospects”.

2023 Strategy and Outlook

Oil prices have been volatile over the past years. In preparation for continued volatility, we have developed multiple scenarios for our 2023 capital expenditures program.

Our preliminary base capital program for 2023 considered a reference oil price assumption of US$80-90 per barrel and calls for approximately US$200-220 million to fund our exploration and development which we intend to fund through cash flows from operations and cash-in-hand, to be allocated approximately as follows:

- Colombia: US$185-210 million. Focus on continuing the development of the core Llanos 34 block, accelerating development and exploration activities in high potential blocks near Llanos 34 plus 3D seismic and other pre-drilling activities to continue adding new plays, leads and prospects.

- Ecuador: US$10-15 million. Focus on three or four gross appraisal and exploration wells plus facilities, environmental and optimization projects in the Perico and Espejo blocks.

In addition, we have developed downside and upside work program scenarios based on different oil prices and project performance. The downside scenario work program considers a reference oil price assumption below US$60 per barrel and consists of an alternative capital expenditure program of approximately US$120-150 million consisting mainly of certain low risk and quick cash flow generating projects. The upside scenario work program considers a reference oil price assumption above US$90 per barrel or higher and consists of an alternative capital expenditure program of approximately US$220-260 million to be selected from identified projects designed to increase reserves and production.

To secure minimum oil prices for our 2023 production and beyond, we have commodity risk management contracts in place covering a portion of our production for the year and monitor market conditions on a continuous basis to evaluate additional new commodity risk management contracts for the future.

Additionally, in 2023, we will target the return of approximately 40-50% of our free cash flow (Adjusted EBITDA less capital expenditures, mandatory interest payments and cash taxes) to shareholders. This distribution will be paid to shareholders through a combination of dividends and discretionary buybacks.

As part of our strategy, we continue to monitor the impact of oil price volatility on our financial condition, cash flows and results of operations.

Our operations

We have a well-balanced portfolio of assets that includes working and/or economic interests in 38 hydrocarbon blocks, 37 of which are onshore blocks, including 9 in production as of December 31, 2022.

Our well-balanced portfolio of assets provides the ability to quickly optimize capital allocation as market conditions change. The current crisis, however, is still evolving and may become more severe and complex. For additional information about the business risks relating to the COVID-19 pandemic and related governmental actions, See “Item 3. Key Information—D. Risk factors—Risks relating to our business— The COVID-19 pandemic has and may continue to adversely impact our business, financial condition, and results of our operations, the global economy, and the demand for and prices of oil and natural gas. The uncertainty of the impact an endemic or pandemic disease may have makes it impossible for us to identify all potential risks related to the pandemic or estimate the ultimate adverse impact that the pandemic may have on our business.”.

Operations in Colombia

As of December 31, 2022, our Colombian assets gave us access to more than 3,793,000 gross exploratory and productive acres across 24 blocks in what we believe to be one of South America’s most attractive oil and gas geographies.

Since we entered Colombia in 2012, we have achieved successful exploration and development activities at our operated Llanos 34 Block, which as of December 31, 2022, accounts for 66.7% of our production and 77.1% of our proved reserves in Colombia.

The table below shows average production and proved oil and gas reserves (derived from D&M Reserves Report) in Colombia for the years ended December 31, 2022, 2021 and 2020:

	2022	2021	2020
Average net oil production (mboepd)	33.6	30.9	33.0
Net proved reserves at year-end (mmboe)	64.6	79.0	89.3

Highlights of the year ended December 31, 2022, related to our operations in Colombia included:

- National electric grid connection and PV solar projects became fully operational since July and November 2022, respectively, and allowed us to continue improving industry-leading cost and carbon footprint performance in the Llanos 34 Block;
- Drilling campaign with 21 gross development wells drilled and putting into production the Jacana, Tigana, Tigui and Tua oil fields in the Llanos 34 Block;
- Drilling campaign with 4 gross development wells drilled and putting into production the Indico oil field in the CPO-5 Block;
- Successful drilling and putting into production the Platanillo Central and Alea NW 1 exploration wells in the Platanillo Block;
- Discovery of a new commercial field called Flamenco in the CPO-5 Block through the successful drilling and put into production of the Cante Flamenco 1 exploratory well;
- Average net oil production increased by 9%, to 33.6 mboepd in 2022 from 30.9 mboepd in 2021;
- Proved oil and gas reserves decreased by 18% to 64.6 mmboe at year-end 2022, from 79.0 mmboe at year-end 2021 after producing 12.0 mmboe;
- Capital expenditures increased by 16% to US$139.2 million in 2022 from US$119.9 million in 2021; and
- Operating costs levels per barrel increased by 2% from US$6.5 in 2021 to US$6.6 in 2022.

Our interests in Colombia include working interests and economic interests. “Working interests” are direct participation interests granted to us pursuant to an E&P contract with the ANH, whereas “economic interests” are indirect participation interests in the net revenues from a given block based on bilateral agreements with the concessionaires.

The map below shows the location of the blocks in Colombia in which we have working and/or economic interests.

(1) Termination of the E&P contract was approved by the ANH and final liquidation is in process.
(2) In process of relinquishment.

The table summarizes information about the blocks in Colombia in which we have working interests as of and for the year ended December 31, 2022.

Block	Gross acres (thousand acres)	Working interest[(1)]	Partners[(2)]	Operator	Net proved reserves (mmboe)	Production (boepd)	Basin	Concession expiration year
Llanos 34	59.1	45 %	Verano Energy	GeoPark	54.3	25,657	Llanos	Exploitation: 2039-2045[(3)]
Llanos 32	8.5	12.5 %	Verano Energy	Verano Energy	1.9	436	Llanos	Exploration: 2022
								Exploitation: 2040-2045[(3)]
VIM-3	46.9	100 %	—	GeoPark	—	—	Magdalena	In process of termination
Llanos 86	255.5	50 %	Hocol	GeoPark	—	—	Llanos	Exploration: 2025
Llanos 87	107.6	50 %	Hocol	GeoPark	—	0	Llanos	Exploration: 2023
Llanos 104	274.8	50 %	Hocol	GeoPark	—	—	Llanos	Exploration: 2025
Llanos 123	88.3	50 %	Hocol	GeoPark	—	—	Llanos	Exploration: 2024
Llanos 124	27.6	50 %	Hocol	GeoPark	—	—	Llanos	Exploration: 2024
Llanos 94	89.2	50 %	Parex	Parex	—	—	Llanos	Exploration: 2023
Andaquíes	114.9	100 %	—	GeoPark	—	—	Putumayo	In process of termination
Coatí	61.8	100 %	—	GeoPark	—	—	Putumayo	Exploration: Currently suspended
CPO-4-1	148.3	50 %	Parex	Parex	—	—	Llanos	Exploration: 2025
CPO-5	490.8	30 %	ONGC Videsh	ONGC Videsh	5.8	5,580	Llanos	Exploration: 2022
								Exploitation: 2042
Mecaya	74.1	50 %	Sierracol Energy	GeoPark	—	—	Putumayo	Exploration: Currently suspended
Platanillo	27.3	100 %	—	GeoPark	2.6	2,077	Putumayo	Exploitation: 2033[(3)]
PUT-8	102.8	50 %	Sierracol Energy	GeoPark	—	—	Putumayo	Exploration: 2022
PUT-9	121.5	50 %	Sierracol Energy	GeoPark	—	—	Putumayo	Exploration: Currently suspended
PUT-12	134.5	60 %	Pluspetrol	GeoPark	—	—	Putumayo	In process of termination
PUT-14	114.6	100 %	—	GeoPark	—	—	Putumayo	In process of termination
PUT-30	95.2	100 %	—	GeoPark	—	—	Putumayo	In process of termination
PUT-36	148.0	50 %	Sierracol Energy	GeoPark	—	—	Putumayo	Exploration: Currently suspended
Tacacho	589.0	50 %	Sierracol Energy	GeoPark	—	—	Putumayo	In process of termination
Terecay	586.6	50 %	Sierracol Energy	GeoPark	—	—	Putumayo	In process of termination

(1) Working interest corresponds to the working interests held by our respective subsidiaries in such block, net of any working interests held by other parties in each block.
(2) Partners with working interests.
(3) The concession expiration year is set on a field by field basis.

The table summarizes information about the blocks in Colombia in which we have economic interests as of and for the year ended December 31, 2022.

Block	Gross acres (thousand acres)	Economic interest[(1)]	Operator	Production (boepd)	Basin
Abanico	25.7	10 %	Frontera	18	Magdalena

(1) Economic interest corresponds to indirect participation interests in the net revenues from the block, granted to us pursuant to a joint operating agreement.

Eastern Llanos Basin:

The Eastern Llanos Basin is a Cenozoic Foreland basin in the eastern region of Colombia. Two giant fields (Caño Limón and Castilla), three major fields (Rubiales, Apiay and Tame Complex) and approximately fifty minor fields had been discovered. The source rock for the basin is located beneath the east flank of the Eastern Cordillera, as a mixed marine-continental shale basinal facies of the Gachetá formation. The main reservoirs of the basin are represented by the Paleogene Carbonera and Mirador sandstones. Within the Cretaceous sequence, several sandstones are also considered to have good reservoirs.

Llanos 34 Block. We are the operator of, and have a 45% working interest in, the Llanos 34 Block, which covers approximately 59,085 gross acres (239 sq. km.). We acquired an interest in and took operatorship of the block in the first quarter of 2012, which at that time had no production, reserves or wells drilled on it, and with 210 sq. km. of existing 3D seismic data on which our team had mapped multiple exploration prospects. From 2012 to 2022 we engaged in exploration and development activities that resulted in 10 new oil fields discoveries and increased proved reserves and oil production year by year up to a peak oil production of 34,995 bopd. Average net production in 2022 was 25,657 bopd and net reserves of 54.3 mmboe. By the end of 2022, we have drilled more than 190 wells, with 155 producer wells that have accumulated more than 159 million barrels of oil. The Llanos 34 Block has three reservoirs: the Guadalupe Formation, which produces 88% of our oil production in the Block, Mirador, which produces 11% of our oil production in the Block and Gacheta, which produces 1% of our oil production in the Block, with an API gravity between 13° and 30.6°. During these 11 years of operation in Llanos 34 Block, we have built all the required infrastructure to produce and manage the fluids of the assets, including 10 production facilities, 59 kilometers of power grid, more than 90 kilometers of flowlines for fluid transfer, 169 kilometers of roads and a 42 kilometers oil pipeline. By the end of 2022, we have transported more than 51 million barrels of oil from Tigana and Jacana fields through the ODCA pipeline further reducing truck traffic, contributing to the reduction of operational risk, costs and carbon emissions. In August 2022, we connected the Llanos-34 Block to the national power grid, reducing risk of shutdown, cost and carbon emissions.

Our partner in the Llanos 34 Block is Verano Energy (a subsidiary of Parex), which has a 55% interest. See "—Our operations." We operate in the block pursuant to an E&P contract with the ANH. See "—Significant Agreements—Colombia—E&P contracts—Llanos 34 Block E&P contract."

Llanos 32 Block. We have a 12.5% working interest in the Llanos 32 Block. The Llanos 32 Block covers approximately 8,556 gross acres (35 sq. km.). Verano Energy is the operator of this block and has an 87.5% working interest. Since 2015, the operator focused on the commissioning of a gas facility on this block to produce natural gas and light crude oil from the Une formation and to facilitate shipment of processed gas south to the adjacent Llanos 34 Block. For the year ended December 31, 2022, our average net production in the Llanos 32 Block was 436 bopd. As of the date of this annual report, outstanding investment commitments related to this block correspond to the drilling of 5 exploratory wells before February 20, 2022. Due to a private agreement with the partner in the block, the investment commitment incurred by us amounts to US$9.2 million. As of the date of this annual report, the five exploratory wells have already been drilled and ANH approval of the fulfillment of the investment commitment is pending.

Abanico Block. In October 1996, Ecopetrol and Explotaciones CMS Nomeco Inc. entered into the Abanico Block association contract. Pacific Rubiales Energy is the operator of, and has a 100% working interest in, the Abanico Block, which covers an area of approximately 25,658 gross acres (103 sq. km.). We do not maintain a direct working interest in the Abanico Block, but rather have a 10% economic interest in the net revenues from the block pursuant to a joint operating agreement initially entered into with Kappa Resources Colombia Limited (now Pacific, who subsequently assigned its participation interest to Cespa de Colombia S.A., who then assigned the interest to Explotaciones CMS Oil & Gas), Maral Finance Corporation and Getionar S.A.

Llanos 86 and Llanos 104 Blocks. We and Hocol (a subsidiary of Ecopetrol), each with fifty percent (50%) working interest executed an E&P contract over these blocks on July 11, 2019, as a result of the Permanent Competitive Process launched by ANH in 2019. We are the operator of these contracts that are in their exploratory phase 1 and cover approximately 530,309 gross acres (2,146 sq. km.). Due to the presence of indigenous communities in the area, we conducted the due prior consultation process with the communities and the process concluded on March 15, 2022. As of the date of this annual report, outstanding investment commitments consist of acquisition of 3D seismic and drilling of one exploratory well in each block for an estimated amount of US$9.9 million for Llanos 86 Block and US$8.8 million for Llanos 104 Block, before March 14, 2025.

Llanos 87 Block. GeoPark and Hocol, each with fifty percent (50%) working interest executed an E&P contract over this block on July 11, 2019, as a result of the Permanent Competitive Process launched by ANH in 2019. We are the operator of this contract that is currently in exploratory phase 1 and covers approximately 107,624 gross acres (435 sq. km.). Phase 1 commitments are reprocessing of 3D seismic, drilling of four exploratory wells and acquisition of aero geophysics for an estimated amount of US$13.8 million before March 9, 2023. As of the date of this annual report, we have already drilled the four committed exploratory wells and ANH approval of the fulfillment of the investment commitment is pending. In March 2023, the ANH approved our request to extend the exploratory phase 1 until May 14, 2023.

Llanos 123 and Llanos 124 Blocks: GeoPark and Hocol, each with fifty percent (50%) working interest executed an E&P contract over these blocks on December 20, 2019, as a result of the Permanent Competitive Process launched by ANH in 2019. We are the operator of these contracts that covers approximately 115,956 gross acres (469 sq. km.). As of the date of this annual report, outstanding investment commitments related to these blocks correspond to (i) reprocessing 3D seismic and drilling of two exploratory wells for Llanos 123 Block with an estimated amount of US$7.1 million before January 14, 2024, and; (ii) the acquisition of 3D seismic, reprocessing of 3D seismic and drilling of three exploratory wells for Llanos 124 Block with an estimated amount of US$10.6 million before January 14, 2024. Other commitments related to the acquisition of geochemistry for both blocks and were credited by executed activities in another block. Drilling of the wells for both blocks is scheduled for 2023.

Llanos 94 Block. On July 24, 2019, the E&P contract was awarded to Parex Energy as a result of the Permanent Competitive Process launched by ANH in 2019. This contract is in its exploratory phase 1 and covers approximately 89,175 gross acres (360.8 sq. km.). We acquired a 50% working interest from Parex and obtained ANH's approval to such transfer in May 2020. Phase 1 commitments are the acquisition of 3D seismic, reprocessing of 3D seismic and drilling of 3 exploratory wells for an estimated amount of US$10.9 million before October 1, 2023. One of the three committed exploratory wells has already been drilled. During 2022, the operator of the block submitted to the ANH requests to transfer part of the pending commitments to the Llanos 34 Block. As of the date of this annual report, the investments needed to fulfill the commitments assigned to the Llanos 34 Block have already been incurred and the ANH approval of such fulfillment is pending

CPO-5 Block. On December 26, 2008, the E&P contract was executed between ONGC Videsh, as operator and the ANH as a result of the Competitive Process "Ronda Colombia 2008". This contract covers approximately 490,825 gross acres (1,986 sq. km.). We hold a 30% working interest since the acquisition of Amerisur in 2020. As of the date of this annual report, this contract is in exploratory phase 2 in which the pending commitment corresponds to the acquisition, processing and interpretation of 73 sq. km. of 3D seismic for an amount of US$2.8 million, and drilling of one exploratory well for an amount of US$6.4 million, to be fulfilled before October 9, 2025. There are three commercial fields called Mariposa, Indico and Flamenco. Average net production in 2022 was 5,580 bopd and net reserves were 5.8 mmboe.

CPO-4-1 Block. On January 18, 2022, the E&P contract was executed between Parex Energy and the ANH as a result of the Permanent Competitive Process launched by ANH in 2019. On April 29, 2022, an amendment to the E&P contract was executed, whereby the ANH approved the assignment of a 50% non-operated working interest to us. As of the date of this annual report, this contract is in exploratory phase 1 and covers approximately 148,263 gross acres (600 sq. km.). The outstanding investment commitment related to the block corresponds to the drilling of an exploratory well for an estimated amount of US$2.9 million before September 19, 2025.

Magdalena Basin:

VIM-3 Block. On July 23, 2014, we were awarded an exploratory license during the 2014 Colombia Bidding Round, carried out by the ANH. The VIM-3 Block is located in the Lower Magdalena Basin. In 2018, we filed a request before the ANH to terminate the E&P contract due to environmental restrictions in the block. These restrictions became apparent once the National Authority of Environmental Licenses issued the environmental license. As of the date of this annual report, the termination was approved by the ANH and the final liquidation of the contract is pending.

Putumayo Basin:

Andaquies Block. We are the operator of and have a 100% working interest in the Andaquies Block, which covers approximately 114,879 gross acres (465 sq. km.). As of the date of this annual report the contract is in phase 3 of the exploration period. On February 14, 2020, we presented our withdrawal from the E&P contract and requested the ANH to approve the transfer of the pending commitments to the Llanos 32 Block. On February 20, 2020, the ANH approved the request. As of the date of this annual report, termination of the E&P contract has been approved by the ANH and the final liquidation of the contract is pending.

Coati Block. We are the operator of and have a 100% working interest in the Coati Block, which covers approximately 61,843 gross acres (250 sq. km.). The outstanding exploration commitment consists of the acquisition of 57 sq. km. of 3D seismic and 30 km. of 2D seismic, for an estimated amount of US$4.5 million. The evaluation area is currently suspended. On November 3, 2022, we submitted to the ANH a request to withdraw from the exploration period of the Coati E&P contract and transfer the pending commitments to other E&P contracts. As of the date of this annual report, the transfer of the investment is being carried out.

Mecaya Block. We are the operator of and have a 50% working interest in the Mecaya Block, which covers approximately 74,128 gross acres (300 sq. km.). Sierracol Energy is the owner of the remaining 50% working interest. As of the date of this annual report, the contract is in unified phases 1 and 2 of the exploration period, which remaining exploration commitment consists of the acquisition of 52.2 sq. km. of 3D seismic for an amount of US$0.6 million. On December 2010, the former operator declared an evaluation area and presented an evaluation program for the Mecaya-1 well (Mecaya Evaluation Program). Both the unified phases 1 and 2 and the evaluation program are currently suspended due to force majeure events (relating to prior consultations).

Platanillo Block. We are the operator of and have a 100% working interest in the Platanillo Block, which covers approximately 27,300 gross acres (110 sq. km.). On September 11, 2009, we began the commercial exploitation of the Platanillo Block. Average net production in 2022 was 2,077 bopd and net reserves of2.6 mmboe.

Putumayo 8 Block. We are the operator of and have a 50% working interest in the Putumayo 8 Block, which covers approximately 102,800 gross acres (416 sq. km.). Sierracol Energy is the owner of the remaining 50% working interest. The contract is in unified phases 1 and 2 of the exploration period. Outstanding investment commitments of US$13.1 million related to this block correspond to the drilling of 3 exploratory wells and the acquisition of 112 sq. km. of 3D seismic before October 15, 2023. Part of the 3D seismic committed in the block has already been acquired during 2020 and 2021. On October 25, 2022, we submitted to the ANH a request to transfer the investment commitment related to the pending 3D seismic to the Platanillo Block. As of the date of this annual report, such investment has been fulfilled and the ANH approval is pending.

Putumayo 9 Block. We are the operator of and have a 50% working interest in the Putumayo 9 Block, which covers approximately 121,453 gross acres (492 sq. km.). Sierracol Energy is the owner of the remaining 50% working interest. As of the date of this annual report, the contract is in phase 1 of the exploration period and outstanding investment commitments of US$4.4 million related to this block correspond to drilling of two exploratory wells before October 14, 2020, and the acquisition of 126.25 sq. km. of 3D seismic. Phase 1 was suspended on June 25, 2019, due to the occurrence of a force majeure event consisting of the issuance of the Municipal Agreement No. 007 of Puerto Guzmán, which prohibits the hydrocarbon exploration and production activities in such municipality.

Putumayo 12 Block. We are the operator of and have a 60% working interest in the Putumayo 12 Block, which covers approximately 134,534 gross acres (544 sq. km.). Pluspetrol Colombia Corporation ("Pluspetrol") is the owner of the remaining 40% working interest. As of the date of this annual report, the contract is in phase 1 of the exploration period, and outstanding investment commitments of US$14.4 million related to this block consist of the drilling of one exploratory well, the acquisition of 131 km. of 2D seismic, and the acquisition of geochemistry before November 29, 2021. On February 23, 2021, we requested the termination of the contract due to the occurrence of force majeure events related with judicial procedures initiated by ethnic communities. As of the date of this annual report, termination of the E&P contract has been approved by the ANH and the final liquidation of the contract is pending.

Putumayo 14 Block. We are the operator of and have a 100% working interest in the Putumayo 14 Block, which covers approximately 114,560 gross acres (464 sq. km.). Exploration commitments in the block correspond to the acquisition of 2D seismic and drilling of an exploratory well for an estimated amount of US$16.1 million. On March 10, 2022, we submitted to the ANH a request to withdraw from the PUT-14 E&P contract and transfer the pending commitments to the Platanillo and CPO-5 Blocks. Once total investment is reached through such transfers, ANH will continue with the contract's termination. As of the date of this annual report, part of the abovementioned investment has already been incurred and the ANH approval of the partial fulfillment is pending.

Putumayo 30 Block. We are the operator of and have a 100% working interest in the Putumayo 30 Block, which covers approximately 95,172 gross acres (385 sq. km.). On February 23, 2021, we submitted to the ANH our request to withdraw from to the E&P contract and transfer the remaining commitments to other E&P contracts. The ANH approved the request. The remaining investment was transferred to Llanos 34 Block and Platanillo Block. As of the date of this annual report, the E&P contract is in process of liquidation.

Putumayo 36 Block. We are the operator of and have a 50% working interest in the Putumayo 36 Block, which covers approximately 148,021 gross acres (599 sq. km.). Sierracol is the owner of the remaining 50% working interest. As part of the prior consultation process, the Ministry of Interior certified the presence of one indigenous community in the area. As of the date of this annual report, the contract is in phase 0 as the applicable prior consultation process must be completed. The outstanding investment commitments of US$11.9 million related to this block consist of the acquisition of 105.6 sq. km. of 3D seismic and the drilling of two exploratory wells. Prior consultation has not been initiated with the ethnic community due to the restrictions from the issuance of Municipal Agreement No. 007 of Puerto Guzmán, which caused the current phase of the process to be suspended.

Tacacho and Terecay Blocks. We are the operator of and have a 50% working interest in the Tacacho and Terecay Blocks, which covers approximately 589,009 gross acres (2,384 sq. km.) and 586,625 gross acres (2,374 sq. km.), respectively. Sierracol Energy is the owner of the remaining 50% working interest. Both contracts are in phase 1, which is currently suspended due to the occurrence of force majeure events related to social and public order conditions of the area. The outstanding investment commitments correspond to (i) the acquisition, processing and interpretation of 480 km. of 2D seismic for the Tacacho Block with an estimated amount of US$1.2 million, and; (ii) the acquisition, processing and interpretation of 476 km. of 2D seismic for the Terecay Block with an estimated amount of US$2.9 million. On September 21, 2022, we submitted to the ANH a request for termination of the E&P contract. As of the date of this annual report, the termination request is under review by the ANH.

As per farm-out agreement executed on November 21, 2018, Sierracol Energy shall carry us in certain exploration activities for the Mecaya, PUT-9, Tacacho and Terecay Contracts.

Operations in Chile

Our Chilean assets currently give us access to 657,000 of gross exploratory and productive acres across 4 blocks in a large fully-operated land base across the Magallanes Basin, with existing reserves, production and cash flows.

Our Chilean blocks are located in the provinces of Última Esperanza, Magallanes and Tierra del Fuego in the Magallanes Basin, a proven oil and gas-producing area. As of December 31, 2022, the Magallanes Basin accounted for all of Chile's oil and gas production.

Substantial technical data (seismic, geological, drilling and production information), developed by us and by ENAP, provides an informed base for new hydrocarbon exploration and development. Shut-in and abandoned fields may also have the potential to be put back in production by constructing new pipelines and plants. Our geophysical analyses suggest additional development potential in known fields and exploration potential in undrilled prospects and plays, including opportunities in the Springhill, Tertiary, Tobífera and Estratos con Favrella formations. The Springhill formation has historically been the source of production in the Fell Block, though the Estratos con Favrella shale formation is the principal source rock of the Magallanes Basin, and we believe it contains unconventional resource potential.

Highlights of the year ended December 31, 2022, related to our operations in Chile included:

- Drilling of two development wells in the Jauke oil field in the Fell Block;
- Average net oil and gas production decreased by 2% to 2,338 boepd in 2022 from 2,397 boepd in 2021;
- Proved oil and gas reserves decreased by 6% to 3.9 mmboe at year-end 2022 from 4.2 at year-end 2021 after producing 0.9 mmboe; and
- Capital expenditures increased by 159% to US$11.1 million in 2022 from US$4.3 million in 2021.

The map below shows the location of the blocks in Chile in which we have working interests.

The table below summarizes information about the blocks in Chile in which we have working interests as of and for the year ended December 31, 2022.

Block	Gross acres (thousand acres)	Working interest (1)	Partners (2)	Operator	Net proved reserves (mmboe)	Production (boepd)	Basin	Concession expiration year
Fell	367.8	100 %	—	GeoPark	3.9	2,338	Magallanes	Exploitation: 2032
Isla Norte	97.7	60 %	ENAP	GeoPark	—	—	Magallanes	Exploration: 2024 Exploitation: 2044
Campanario	144.2	50 %	ENAP	GeoPark	—	—	Magallanes	Exploration: 2024 Exploitation: 2045
Flamenco	47.1	50 %	ENAP	GeoPark	—	—	Magallanes	Exploitation: 2044

(1) Working interest corresponds to the working interests held by our respective subsidiaries in such block, net of any working interests held by other parties in each block.
(2) Partners with working interests.

Fell Block

In 2006, we became the operator and 100% interest owner of the Fell Block. When we first acquired an interest in the Fell Block in 2002, it had no material oil and gas production. Since then, we have completed more than 1,100 sq. km. of 3D seismic surveys and drilled 141 exploration and development wells. In the year ended December 31, 2022, we produced an average of 2,338 boepd in the Fell Block, consisting of 81.2% gas.

The Fell Block has an area of 367,800 gross acres (1,488 sq. km.) and its center is located approximately 140 km. northeast of the city of Punta Arenas. It is bordered on the north by the international border between Argentina and Chile and on the south by the Magellan Strait.

From 2006 through August 2011, we successfully explored and developed the Fell Block, which allowed us to transition approximately 84% of the Fell Block's area from an exploration phase into an exploitation phase, which we expect will last through 2032. There are no minimum work and investment commitments under the Fell Block CEOP associated with the exploitation phase.

The Fell Block is located in the north-eastern part of the Magallanes Basin. The principal producing reservoir is composed of sandstones in the Springhill formation, at depths of 2,200 to 3,500 meters. Additional reservoirs have been discovered and put into production in the Fell Block—namely, Tobífera formation volcanoclastic rocks at depths of 2,900 to 3,600 meters, and Upper Tertiary and Upper Cretaceous sandstones, at depths of 700 to 2,000 meters.

The Fell Block also contains the Estratos con Favrella shale reservoir as a broad area within Fell Block (1,000 sq. km.) which appears to be in the oil window for this play.

Tierra del Fuego Blocks (Isla Norte, Campanario and Flamenco Blocks)

In the first and second quarters of 2012, we entered into three CEOPs with ENAP and Chile granting us working interests in the Isla Norte, Campanario and Flamenco Blocks, located in the center-north of the Tierra del Fuego Province of Chile. We are the operator of all three of these blocks, with working interests of 60%, 50% and 50%, respectively. We believe that these three blocks, which collectively cover 347,700 gross acres (1,407 sq. km.) and are geologically contiguous to the Fell Block.

Flamenco Block. We are the operator of, and have a 50% working interest in, the Flamenco Block, in partnership with ENAP. The block covers approximately 47,135 gross acres (191 sq. km.). In June 2013, we discovered a new oil and gas field in the block following the successful testing of the Chercán 1 well, the first well drilled by us in Tierra del Fuego. We have completed all the committed activities for the first and second exploration periods under the CEOP governing the Flamenco Block. We opted out of the third exploration period, and as of the date of this annual report, the exploration phase in the Flamenco Block has been concluded.

Isla Norte Block. We are the operator of and have a 60% working interest in partnership with ENAP in the Isla Norte Block, which covers approximately 97,650 gross acres (395 sq. km.). As of the date of this annual report, we had completed 100% of the commitments of the first exploratory period and outstanding investment commitments of US$0.9 million related to this block correspond to one exploratory well of the second exploratory period.

Campanario Block. We are the operator of, and have a 50% working interest in, the Campanario Block, in partnership with ENAP. The block covers approximately 144,150 gross acres (583 sq. km.). As of the date of this annual report, we had completed 100% of the commitments of the first exploratory period and outstanding investment commitments of US$5.0 million related to this block correspond to two exploratory wells of the second exploratory period. The drilling campaign relating to the committed wells of Isla Norte and Campanario Blocks started in February 2020 but due to the COVID-19 pandemic, the execution of the 2020 work plan was interrupted.

Therefore, we presented to the Ministry of Energy notifications of declaration of force majeure, which were approved and we obtained an extension of the second exploratory period to fulfill the commitments of the Campanario and Isla Norte Blocks until the first half of 2024.

As of the date of this annual report, we have an outstanding investment commitment of US$5.9 million, consisting of two exploratory wells in the Campanario Block before April 25, 2024 and one exploratory well in the Isla Norte Block before February 19, 2024.

Operations in Brazil

Our Brazilian assets currently give us access to 61,400 of gross exploratory and productive acres across 6 blocks (5 exploratory blocks and the BCAM-40 Concession, which is in production phase) in an attractive oil and gas geography.

Highlights of the year ended December 31, 2022, related to our operations in Brazil included:

- Average net oil and gas production 1,516 boepd (98.6% gas) in the year ended December 31, 2022, as compared to 1,919 boepd in 2021;

- Proved oil and gas reserves decreased by 31% to 1.6 mmboe at year-end 2022, from 2.3 mmboe at year-end 2021 after producing 0.6 mmboe; and

- We maintained our 10% non-operated working interest in the Manati gas field as the deadline to complete the divestment expired on March 31, 2022.

The map below shows the location of our concessions in Brazil in which we have a current or future working interest:

The following table sets forth information as of December 31, 2022, on our concessions in Brazil in which we have a current or future working interest:

Concession	Gross acres (thousand acres)	Working interest[(1)]	Partners	Operator	Net proved reserves (mmboe)	Production (boepd)	Basin	Concession expiration year
POT-T-785	7.9	70 %	Petroil	GeoPark	—	—	Potiguar	Exploration: 2025 Exploitation: 2050
REC-T 58	7.8	100 %	—	GeoPark	—	—	Recôncavo	Exploration: 2025 Exploitation:2052
REC-T 67	7.7	100 %	—	GeoPark	—	—	Recôncavo	Exploration: 2025 Exploitation:2052
REC-T 77	7.7	100 %	—	GeoPark	—	—	Recôncavo	Exploration: 2025 Exploitation:2052
POT-T 834	7.5	100 %	—	GeoPark	—	—	Potiguar	Exploration: 2025 Exploitation:2052
Manati [(2)]	22.8	10 %	Petrobras; Enauta; PetroRio	Petrobras	1.6	1,516	Camamu-Almada	Exploitation: 2029

(1) Working interest corresponds to the working interests held by our respective subsidiaries in such block, net of any working interests held by other parties in each block.

(2) On November 22, 2020, we signed an agreement to sell our 10% non-operated working interest in the Manati Block in Brazil. The transaction was subject to certain conditions to be met before March 31, 2022. As of March 31, 2022, the required conditions were not met, and we decided not to extend this deadline. As a result, we continue to own our 10% interest in the block.

Manati Field

We have a 10% working interest in the BCAM-40 Concession, which originally included an interest in the Manati Field, which is located in the Camamu-Almada Basin. Petrobras is the operator of, and has a 35% working interest in, the BCAM-40 Concession, which covers approximately 22,784 gross acres (92.2 sq. km.). In addition to us, Petrobras' partners in the block are PetroRio S.A. and Enauta Energia S.A. (Enauta), with 10% and 45% working interests, respectively. Petrobras operates the BCAM-40 Concession pursuant to a concession agreement with the ANP, executed on August 6, 1998. See "—Significant Agreements—Brazil—Overview of concession agreements—BCAM-40 Concession Agreement." In September 2009, Petrobras announced the relinquishment of BCAM-40's exploration area within the concession to the ANP, except for the Manati Field.

The Manati Field is located 65 km. south of Salvador, offshore at a water depth of 35 meters. The field was discovered in October 2000, and, in 2002, Petrobras declared the field commercially viable. Production began in January 2007. As of December 31, 2022, 11 wells had been drilled in the Manati Field, 6 of which are productive and connected to a fixed production platform installed at a depth of 35 meters, located 9 km. from the coast of the State of Bahia. From the platform, the gas flows by sea and land through a 125 km. pipeline to the Estação Vandemir Ferreira or EVF gas treatment plant. The gas is sold to Petrobras up to a maximum volume as determined in the existing Petrobras Gas Sales Agreement (as defined below).

In 2020, we executed the 15th Amendment to the Petrobras Gas Sales Agreement in order to reflect the negotiations to mitigate the effects of the COVID-19 pandemic on the natural gas agents. Additionally, and in parallel a Term of Settlement of Outstanding Issues was executed to reflect the negotiations related to the take or pay agreement.

On November 22, 2020, we signed an agreement to sell our 10% non-operated working interest in the Manati gas field to Gas Bridge for a total consideration of R$144.4 million (approximately $27 million as of the date of the agreement at the exchange rate of R$5.35 to US$1.00), including a fixed payment of R$124.4 million plus an earn-out of R$20.0 million, which was subject to obtaining certain regulatory approvals. The transaction was subject to certain conditions that should have been met before March 31, 2022. As of March 31, 2022, the required conditions were not met and we decided not to extend this deadline. As a result, we continue to own our 10% interest in the block.

REC-T-128 Concession

The block REC-T-128 was bid for in partnership with Geosol with a 70% working interest for us and 30% working interest for Geosol. The total commitment to the ANP was R$10.7 million (approximately US$1.9 million at the December 31, 2021, exchange rate of R$5.60 to US$1.00) during the first exploratory period and consisted of the acquisition of 9 sq. km. of 3D seismic, drilling of one well and performing geochemical analysis at two geological levels.

In July 2020, we initiated a farm-out process to sell our 70% interest. On March 1, 2021, the farm-out agreement was signed and closing of the transaction took place in May 2021, after receipt of the corresponding customary regulatory approvals. The total consideration of US$1.1 million was paid in 2021 and the contingent payment of up to US$0.7 million was subject to international oil price and field production performance. On August 1, 2022, we collected the contingent payment of US$710,000.

POT-T-785 Concession

The POT-T-785 block covers an area of 7,875 acres in the Potiguar Basin, surrounded by producing fields operated by Petrobras. Total commitment to the ANP was R$1.2 million (US$0.2 million, at the December 31, 2022, exchange rate of R$5.22 to US$1.00) during the first exploratory period and is equivalent to acquiring 4 sq. km. of 3D seismic and performing geochemical analysis before April 29, 2025. As of December 31, 2022, the estimated remaining commitment in the POT-T-785 block amounts to US$0.1 million.

ANP's First Open Acreage Bid Round

During ANP's First Open Acreage Bid Round held in September 2019, we were awarded four exploratory blocks, one in the Potiguar Basin (Block POT-T-834) and three on the Recôncavo Basin (Blocks REC-T-58, REC-T-67 and REC-T-77). The Concession Agreements were executed on February 2020. As of December 31, 2022, the estimated commitment in the blocks amounted to US$0.6 million to be executed before February 14, 2025.

Operations in Argentina

The map below shows the location of the blocks in Argentina in which we have working interests as of December 31, 2022.

(1) In process of relinquishment as of December 31, 2022.
(2) As of the date of this annual report, the suspension of the terms of the exploratory period and the transfer of the investment commitment to another block are under negotiation.

Block	Gross acres (thousand acres)	Working interest [1]	Operator	Net proved reserves (mmboe)	Production (boepd)	Basin	Expiration concession year
Puelen	260.2	18 %	Pluspetrol	—	—	Neuquén	In process of relinquishment
Los Parlamentos	330.9	50 %	YPF	—	—	Neuquén	Exploration: 2022

(1) Working interest corresponds to the working interests held by our respective subsidiaries in such block, net of any working interests held by other parties in each block.

Los Parlamentos Block Farm-in Agreement

In June 2018, we announced the acquisition of a 50% working interest in the Los Parlamentos exploratory block in partnership with YPF, the largest oil and gas producer in Argentina. In accordance with the partnership agreement, YPF assumed the operationship of the block and we assumed a commitment which includes two exploratory wells and additional 3D seismic, that amounts to US$6 million at our working interest, for the first exploratory period ending on October 30, 2022. As of the date of this annual report, the suspension of the terms of the exploratory period and the transfer of the investment commitment to another block are under negotiation.

2014 Mendoza Bidding Round

On August 20, 2014, the consortium of Pluspetrol and us was awarded two exploration licenses in the Sierra del Nevado and Puelen Blocks, as part of the 2014 Mendoza Bidding Round in Argentina, carried out by Empresa Mendocina de Energía S.A. ("EMESA"). The consortium consists of Pluspetrol (operator with a 72% working interest), EMESA (non-operator with a 10% working interest) and us (non-operator with an 18% working interest). As of December 31, 2022, we fulfilled the commitments in the Puelen and Sierra del Nevado Blocks and we are in process of relinquishing the Puelen Block. Final approval for the relinquishment of Sierra del Nevado Block was obtained on February 16, 2022.

Operations in Ecuador

The map below shows the location of the blocks in Ecuador in which we have working interests as of December 31, 2022.

The table below summarizes information about the blocks in Ecuador in which we have working interests as of December 31, 2022.

Block	Gross acres (thousand acres)	Working interest [(1)]	Operator	Net proved reserves (mmboe)	Production (boepd)	Basin	Expiration concession year
Espejo	15.7	50 %	GeoPark	0.0	21	Oriente	Exploration: 2025
							Exploitation: 2045
Perico	17.7	50 %	Frontera	0.3	827	Oriente	Exploration: 2025
							Exploitation: 2045

(1) Working interest corresponds to the working interests held by our respective subsidiaries in such block, net of any working interests held by other parties in each block.

Highlights of the year ended December 31, 2022, related to our operations in Ecuador include:

- Three exploration wells (Jandaya 1, Tui 1 and Yin 1) were drilled and completed in the Perico Block. Together, they were producing 2,005 boepd gross at year-end;
- Acquisition of 60 sq km of 3D seismic in the Espejo Block;
- One exploration well (Pashuri 1) was drilled and completed in the Espejo Block. It was producing 337 boepd gross at year-end;
- Proved oil reserves of 0.3 mmboe in the Perico and Espejo Blocks at year-end 2022;
- Capital expenditures increased by 269% to US$18.5 million in 2022 from US$5.0 million in 2021.

Espejo and Perico blocks

On May 22, 2019, we signed final participation contracts for the Espejo and Perico Blocks which were awarded to us in the Intracampos Bid Round held in Quito, Ecuador in April 2019. We are the operator of the Espejo Block with a 50% working interest and Frontera is the operator of the Perico Block with 50% working interest. We assumed a commitment of carrying out 3D seismic and drilling four exploration wells in the Espejo Block for an estimated amount of US$20.9 million during the first exploratory period ending June 17, 2025 and drilling four exploratory wells in the Perico Block for an estimated amount of US$18.1 million during the first exploratory period ending June 16, 2025. As of the date of this annual report, we have drilled three exploratory wells in the Perico Block and we have completed the acquisition of 60 sq km of 3D seismic and drilled two exploratory wells in the Espejo Block.

Oil and natural gas reserves and production

Our reserves

The following table sets forth our oil and natural gas net proved reserves as of December 31, 2022, which is based on the D&M Reserves Report.

	Net proved reserves As of December 31, 2022			
	Oil (mmbbl)	Natural gas (bcf)	Total net proved reserves (mmboe)(1)	% Oil
Net proved developed				
Colombia	46.6	1.1	46.8	100 %
Chile	1.1	14.1	3.5	32 %
Brazil	0.0	9.4	1.6	1 %
Ecuador	0.3	—	0.3	100 %
Total net proved developed	**48.1**	**24.6**	**52.2**	**92 %**
Net proved undeveloped				
Colombia	17.8	—	17.8	100 %
Chile	0.5	—	0.5	100 %
Brazil	—	—	—	— %
Ecuador	—	—	—	— %
Total net proved undeveloped (2)	**18.2**	**—**	**18.2**	**100 %**
Total net proved (Colombia, Chile, Brazil and Ecuador)	**66.3**	**24.6**	**70.4**	**94 %**

(1) We calculate one barrel of oil equivalent as six mcf of natural gas.

(2) We plan to put 100% of our reported 2022 year-end proved undeveloped reserves into production through activities to be implemented within five years of initial disclosure.

We had net proved reserves of 70.4 mmboe at December 31, 2022, compared to net proved reserves of 87.8 mmboe as of December 31, 2021.

The 20% decrease in net proved reserves in 2022, not including annual production, is mainly attributable to:

- Change in the royalties payment in certain fields in Colombia from cash to kind, resulting in a 3.6 mmboe decrease.
- Lower than expected performance in the Manati Field in Brazil, resulting in a 0.3 mmboe decrease.
- Divestment of the Aguada Baguales, Puesto Touquet and El Porvenir Blocks in Argentina, resulting in a 2.3 mmboe decrease.

This was partially offset by:

- Higher average prices in Colombia, Chile and Brazil, resulting in a 1.0 mmboe increase.
- Higher than expected performance in Colombia and Chile, resulting in a 0.7 mmboe increase.
- Extensions and discoveries that resulted in an increase of 0.8 mmboe due to the new Cante Flamenco field in the CPO-5 Block in Colombia and the new Jandaya, Yin and Tui fields in the Perico Block and the new Pashuri field in the Espejo Block in Ecuador.

During the year ended December 31, 2022, we had 12.3 mmboe of our proved undeveloped reserves from December 31, 2021, converted to proved developed reserves due to development drilling in the Jacana, Tigana and Tigui oil fields in the Llanos 34 Block and the Indico oil field in the CPO-5 Block. For further information relating to the reconciliation of our net proved reserves for the years ended December 31, 2022, 2021 and 2020, please see Table 5 included in Note 38 (unaudited) to our Consolidated Financial Statements.

Internal controls over reserves estimation process

We maintain an internal staff of petroleum engineers and geosciences professionals who work closely with our independent reserves engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserves engineers in their estimating process and who have knowledge of the specific properties under evaluation. Our Chief Technical Officer, Augusto Zubillaga, is primarily responsible for overseeing the preparation of our reserves estimates and for the internal control over our reserves estimation. He has over 26 years of experience in production, engineering, well completion, corrosion control, reservoir management and field development. See "Item 6. Directors, Senior Management and Employees—A. Directors and senior management."

In order to ensure the quality and consistency of our reserves estimates and reserves disclosures, we maintain and comply with a reserves process that satisfies the following key control objectives:

- estimates are prepared using generally accepted practices and methodologies;
- estimates are prepared objectively and free of bias;
- estimates and changes therein are prepared on a timely basis;
- estimates and changes therein are properly supported and approved; and
- estimates and related disclosures are prepared in accordance with regulatory requirements.

Throughout each fiscal year, our technical team meets with Independent Qualified Reserves Engineers, who are provided with full access to complete and accurate information pertaining to the properties to be evaluated and all applicable personnel. This independent assessment of the internally-generated reserves estimates is beneficial in ensuring that interpretations and judgments are reasonable and that the estimates are free of preparer and management bias.

Recognizing that reserves estimates are based on interpretations and judgments, differences between the proved reserves estimates prepared by us and those prepared by an Independent Qualified Reserves Engineer of 10% or less, in aggregate, are considered to be within the range of reasonable differences. Differences greater than 10% must be resolved in the technical meetings. Once differences are resolved, the independent Qualified Reserves Engineer sends a preliminary copy of the reserves report to be reviewed by the Corporate Reserves team and the Executive Committee, integrated by the Chief Executive Officer, Chief Financial Officer, Chief Technical Officer, Chief Operating Officer, Chief Strategy, Sustainability and Legal Officer and Chief People Officer. A final copy of the Reserves Report is sent by the Independent Qualified Reserve Engineer to be approved and signed by the Executive Committee. See "Item 6. Directors, Senior Management and Employees—C. Board Practices—Committees of our board of directors."

Independent reserves engineers

Reserves estimates as of December 31, 2022, for Colombia, Chile, Brazil and Ecuador included elsewhere in this annual report are based on the D&M Reserves Report, dated February 23, 2023, and effective as of December 31, 2022. The D&M Reserves Report, a copy of which has been filed as an exhibit to this annual report, was prepared in accordance with SEC rules, regulations, definitions and guidelines at our request in order to estimate reserves and for the areas and period indicated therein.

DeGolyer and MacNaughton Corp. ("DeGolyer and MacNaughton" or "D&M), a Delaware corporation with offices in Dallas, Houston, Moscow, Algiers, Astana and Buenos Aires has been providing consulting services to the oil and gas industry since 1936. The firm has more than 200 professionals, including engineers, geologists, geophysicists, petrophysicists and economists that are engaged in the appraisal of oil and gas properties, the evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies and equity studies related to the domestic and international energy industry. DeGolyer and MacNaughton restricts its activities exclusively to consultation and does not accept contingency fees, nor does it own operating interests in any oil, gas or mineral properties, or securities or notes of its clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. The firm is a Texas Registered Engineering Firm.

The D&M Reserves Report covered 100% of our total reserves. In connection with the preparation of the D&M Reserves Report, DeGolyer and MacNaughton prepared its own estimates of our proved reserves. In the process of the reserves evaluation, DeGolyer and MacNaughton did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of DeGolyer and MacNaughton that brought into question the validity or sufficiency of any such information or data, DeGolyer and MacNaughton did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. DeGolyer and MacNaughton independently prepared reserves estimates to conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4 10(a)(1)-(32) of Regulation S-X. DeGolyer and MacNaughton issued the D&M Reserves Report based upon its evaluation. D&M's primary economic assumptions in estimates included oil and gas sales prices determined according to SEC guidelines, future expenditures and other economic assumptions (including interests, royalties and taxes) as provided by us. The assumptions, data, methods and procedures used, including the percentage of our total reserves reviewed in connection with the preparation of the D&M Reserves Report were appropriate for the purpose served by such report, and DeGolyer and MacNaughton used all methods and procedures as it considered necessary under the circumstances to prepare such reports.

However, uncertainties are inherent in estimating quantities of reserves, including many factors beyond our and our independent reserves engineers' control. Reserves engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserves estimate is a function of the quality of available data and its interpretation. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, economic factors such as changes in product prices or development and production expenses, and regulatory factors, such as royalties, development and environmental permitting and concession terms, may require revision of such estimates. Our operations may also be affected by unanticipated changes in regulations concerning the oil and gas industry in the countries in which we operate, which may impact our ability to recover the estimated reserves. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserves estimates.

Technology used in reserves estimation

According to SEC guidelines, proved reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with "reasonable certainty" to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

There are various generally accepted methodologies for estimating reserves including volumetrics, decline analysis, material balance, simulation models and analogies. Estimates may be prepared using either deterministic (single estimate) or probabilistic (range of possible outcomes and probability of occurrence) methods. The particular method chosen should be based on the evaluator's professional judgment as being the most appropriate, given the geological nature of the property, the extent of its operating history and the quality of available information. It may be appropriate to employ several methods in reaching an estimate for the property.

Estimates must be prepared using all available information (open and cased hole logs, core analyses, geologic maps, seismic interpretation, production/injection data and pressure test analysis). Supporting data, such as working interest, royalties and operating costs, must be maintained and updated when such information materially changes.

Proved undeveloped reserves

As of December 31, 2022, we had 18.2 mmboe in proved undeveloped reserves, a decrease of 14.3 mmboe, or 44%, over our December 31, 2021, proved undeveloped reserves of 32.5 mmboe. Changes for the year ended December 31, 2022, include:

(i) a decrease of 12.3 mmboe in Colombia due to the conversion of proved undeveloped reserves to proved developed reserves in the Llanos 34 and CPO-5 Blocks;

(ii) an increase of 0.1 mmboe in Colombia due to the discovery of the new Cante Flamenco oil field in the CPO-5 Block;

(iii) a decrease of 0.6 mmboe in Argentina due to the divestment of the Aguada Baguales, El Porvenir and Puesto Touquet Blocks;

(iv) a decrease of 0.8 mmboe due to a lower than expected performance in Colombia (0.6 mmboe) and Chile (0.2 mmboe);

(v) a decrease of 0.7 mmboe due to change in the royalties payment in certain fields in Colombia from cash to kind;

(vi) an increase of 0.2 mmboe due to higher oil average prices in Colombia;

(vii) a decrease of 0.2 mmboe due to lower oil and gas average prices in Chile;

Of our 18.2 mmboe of net proved undeveloped reserves, 17.8 mmboe (97.4%) and 0.5 mmboe (2.6%) were located in Colombia and Chile, respectively.

During 2022, we incurred approximately US$50.4 million in capital expenditures in Colombia to convert such proved undeveloped reserves to proved developed reserves.

No net proved undeveloped reserves were located in Brazil as of December 31, 2022.

The following table shows the evolution of total net proved undeveloped ("PUD") reserves in the year ended December 31, 2022.

Total Net Proved Undeveloped ("PUD") Reserves at December 31, 2021	**32.5**
(All amounts shown in mmboe)	
Plus: Extensions, discoveries and acquisitions:	
-Colombia	0.1
Less: Disposal of minerals in place	
-Argentina	(0.6)
Less: PUD Reserves converted to proved developed reserves:	
-Colombia	(12.3)
Plus/less: PUD Reserves revisions and movement to/from other categories:	
-Colombia	(1.1)
-Chile	(0.4)
Total Net Proved Undeveloped ("PUD") Reserves at December 31, 2022	**18.2**

Production, revenues and price history

The following table sets forth certain information on our production of oil and natural gas in Colombia, Chile, Brazil, Argentina and Brazil for each of the years ended December 31, 2022, 2021 and 2020.

	Average daily production[1]												
	As of December 31,												
	2022					2021				2020			
	Colombia	Chile	Brazil	Arg [2]	Ecuador	Colombia	Chile	Brazil	Arg [2]	Colombia	Chile	Brazil	Arg [2]
Oil production													
Average crude oil production (bopd)	33,640	441	21	80	848	30,920	313	26	1,215	33,039	395	62	1,364
Average sales price of crude oil (US$/bbl)	82.7	94.7	103.1	56.7	89.9	58.3	62.8	70.2	56.4	30.6	38.0	39.6	42.0
Natural Gas production													
Average natural gas production (mcfpd)	776	11,387	8,967	416	—	1,374	12,507	11,357	5,529	1,133	17,084	8,220	5,556
Average sales price of natural gas (US$/mcf)	4.5	3.8	6.4	2.0	—	4.4	3.4	5.2	2.7	5.5	2.7	4.3	2.3
Oil and gas production cost													
Average operating cost (US$/boe)	6.6	16.1	7.4	24.0	27.1	6.5	12.3	4.6	20.8	5.4	8.2	5.8	19.8
Average royalties and economic rights (US$/boe)	21.0	1.5	3.1	5.0	—	9.6	0.9	2.6	6.1	2.7	0.6	2.2	4.8
Average production cost (US$/boe)[3]	27.6	17.6	10.5	29.0	27.1	16.2	13.2	7.2	26.9	8.1	8.8	8.0	24.5

(1) We present production figures net of interests due to others, but before deduction of royalties, as we believe that net production before royalties is more appropriate in light of our foreign operations and the attendant royalty regimes.
(2) "Arg" is Argentina.
(3) Calculated pursuant to FASB ASC 932.

The following table sets forth certain information on our production of oil and natural gas by final product sold in Colombia, Chile, Brazil, Argentina and Ecuador for each of the years ended December 31, 2022, 2021 and 2020.

	2022		2021		2020	
	Oil	Gas	Oil	Gas	Oil	Gas
	Mbbl	MMcf	Mbbl	MMcf	Mbbl	MMcf
Tigana oil field(1)	4,057	—	3,670	—	4,250	—
Jacana oil field(1)	4,678	—	4,023	—	4,152	—
Rest of Colombia	3,543	283	2,747	502	2,584	413
Chile	161	4,156	100	4,403	134	6,175
Brazil	8	3,273	9	3,796	7	2,785
Argentina	29	152	434	1,584	505	1,525
Ecuador	310	—	—	—	—	—
Total	**12,786**	**7,864**	**10,983**	**10,285**	**11,632**	**10,898**

(1) The Tigana (discovered in 2013) and Jacana (discovered in 2015) oil fields in Colombia are separately included in the table above as those oil fields individually contain more than 15% of our total proved reserves as of each of the years indicated above.

Drilling activities

The following table sets forth the exploratory wells we drilled during the years ended December 31, 2022, 2021 and 2020.

	Exploratory wells(1)											
	2022				2021				2020			
	Colombia	Chile	Brazil	Ecuador	Colombia	Chile	Brazil	Argentina	Colombia	Chile	Brazil	Argentina
Productive(2)												
Gross	4.0	—	—	4.0	3.0	—	—	—	1.0	—	—	—
Net	2.6	—	—	2.0	1.9	—	—	—	0.3	—	—	—
Dry(3)												
Gross	4.0	—	—	—	3.0	—	—	—	1.0	1.0	—	—
Net	2.3	—	—	—	0.8	—	—	—	0.3	1.0	—	—
Total												
Gross	8.0	—	—	4.0	6.0	—	—	—	2.0	1.0	—	—
Net	4.9	—	—	2.0	2.7	—	—	—	0.6	1.0	—	—

(1) Includes appraisal wells.
(2) A productive well is an exploratory, development, or extension well that is not a dry well.
(3) A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

The following table sets forth the development wells we drilled during the years ended December 31, 2022, 2021 and 2020.

	Development wells											
	2022				2021				2020			
	Colombia	Chile	Brazil	Ecuador	Colombia	Chile	Brazil	Argentina	Colombia	Chile	Brazil	Argentina
Productive(1)												
Gross	28.0	1.0	—	—	24.0	—	—	—	19.0	—	—	—
Net	12.0	1.0	—	—	10.8	—	—	—	8.6	—	—	—
Dry(2)												
Gross	2.0	1.0	—	—	—	—	—	—	—	—	—	—
Net	0.9	1.0	—	—	—	—	—	—	—	—	—	—
Total												
Gross	30.0	2.0	—	—	24.0	—	—	—	19.0	—	—	—
Net	12.9	2.0	—	—	10.8	—	—	—	8.6	—	—	—

(1) A productive well is an exploratory, development, or extension well that is not a dry well.
(2) A dry well is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Developed and undeveloped acreage

The following table sets forth certain information regarding our total gross and net developed and undeveloped acreage in Colombia, Chile, Brazil, Argentina and Ecuador as of December 31, 2022.

	Acreage(1)				
	Colombia	Chile	Brazil	Argentina	Ecuador
	(in thousands of acres)				
Total developed acreage					
Gross	22.4	5.3	4.1	—	1.1
Net	11.4	5.3	0.4	—	0.5
Total undeveloped acreage					
Gross	3,744.5	651.5	57.3	591.1	32.3
Net	2,011.5	516.8	38.1	212.3	16.2
Total developed and undeveloped acreage					
Gross	3,766.9	656.8	61.4	591.1	33.4
Net	2,022.9	522.1	38.5	212.3	16.7

(1) Developed acreage is defined as acreage assignable to productive wells. Undeveloped acreage is defined as acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas regardless of whether such acreage contains proved reserves. Net acreage is based on our working interest.

Productive wells

The following table sets forth our total gross and net productive wells as of February 28, 2023. Productive wells consist of producing wells and wells capable of producing, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Productive wells(1)			
	Colombia	Chile	Brazil	Ecuador
Oil wells				
Gross	174.0	14.0	-	4.0
Net	88.3	14.0	-	2.0
Gas wells				
Gross	2.0	13.0	6.0	-
Net	0.3	13.0	0.6	-

(1) Includes wells drilled by other operators, prior to our commencing operations, and wells drilled in blocks in which we are not the operator. A productive well is an exploratory, development, or extension well that is not a dry well.

Present activities

As of February 28, 2023, we drilled six productive wells in Colombia adding approximately 3,332 bopd gross as follows:

- Five wells were drilled in the Llanos 34 Block in Colombia (Tigui 5 ST, Tua SW 2, Guaco Sur 1, Tigui 73 and Tigui 30), adding approximately 2,921 bopd gross; and
- One well was drilled in the Platanillo Block in Colombia (Platanillo Norte 1), adding approximately 411 bopd gross.

Additionally, as of the date of this annual report, the drilling campaign of four exploratory wells in the Llanos 87 Block is ongoing and its results are under evaluation.

Our average consolidated production in January and February 2023, was below its potential mainly due to temporary shut-in production of the Indico 6 and Indico 7 wells in the CPO-5 Block in Colombia. The Indico 6 and Indico 7 wells were drilled in late 2022 and together tested over 11,000 bopd gross (3,300 bopd at our working interest). After initial production tests, these two wells were shut in after the ANH requested that the CPO-5 Block operator temporarily suspend production from these wells until definitive surface facilities are completed. The operator of the CPO-5 Block is executing all required activities and expects to resume production in these wells in the second quarter of 2023.

Marketing and delivery commitments

Colombia

Our production in Colombia consists primarily of crude oil which is sold according to price formulas based on market reference indices (Brent price, Vasconia and Oriente differential) and discounts that consider transportation costs and quality adjustments.

During 2022, our sales were allocated on a competitive basis to leading industry participants, including traders and other producers. We continued to deliver at both at well-head and at various points in the Colombian pipeline system and via Ecuador for the Putumayo production.

Our sales strategy is aimed at securing the highest available pricing for our production while securing a reliable and safe path to market. To that end, we focus on developing synergies and strategic partnerships with both clients and the national transport systems, in order to obtain a reduction in costs and increased revenues by making use of the best alternatives available. Such is the case of the implementation of an unloading facility at Jaguey Station in partnership with Oleoducto de Los Llanos (ODL) in 2015. This unloading facility is located 42 km. away from the Llanos 34 Block and allowed for reduced trucking distance and associated costs. Additionally, during 2019 we completed a project to connect the Llanos 34 Block to the ODL pipeline via a flowline. In the third quarter of 2019, we started sending our Jacana production volumes via this flowline to the ODL pipeline, eliminating trucking for that portion of our production and allowing further cost efficiencies and increased operational reliability. In November 2020, the flowline was converted into the Oleoducto del Casanare ("ODCA") receiving full authorization from the Ministry of Energy and Mines to operate as such, determining the regulated tariff and allowing the transportation on of third party crudes. In 2020 we also inaugurated an unloading facility in Jacana, allowing for volumes of other fields to be transported via the ODCA. At the end of 2020, we connected the Tigana field to ODCA, further reducing transport of our volumes via truck. During 2021, ODCA was a central piece of our crude transportation in Colombia, including volumes of Jacana, Tigana and other fields. In 2021, we also entered into an agreement to connect the third party owned Cabrestero Block to ODCA, which allows us to transport third party crude. The connection was completed during the first half of 2022 and we began to transport third-party crude oil through the ODCA.

In the case of the Platanillo Block in the Putumayo Basin, we gather the crude via truck and flowlines to pump it towards Ecuador via the Oloeducto Binacional Amerisur ("OBA"). This pipeline is operated by us and our affiliates and connects us to the Ecuadorean pipeline system via RODA allowing us to sell our production FOB in Esmeraldas port in Ecuador. We hold transport contracts with RODA and SOTE for the transport, storage and loading of our crude in Ecuador.

If we were to lose any of our customers, the loss could temporarily delay production and sale of our oil in the corresponding block. However, given the wide availability of customers for Colombian crude, we believe we could identify a substitute customer to purchase the impacted production volumes in a very short period of time.

Chile

Our customer base in Chile is limited in number and primarily consists of ENAP and Methanex. For the year ended December 31, 2022, we sold 100% of our oil production in Chile to ENAP and 100% of our gas production to Methanex, with sales to ENAP and Methanex accounting for 3% of our total revenues.

We have a long-lasting commercial relationship with ENAP and have been selling our crude to them for the past years. We have a sales agreement with ENAP whereby. ENAP has committed to purchase our oil production in the Fell Block in the amounts that we produce, subject to the limitation of available storage capacity at the Gregorio Terminal. The sales agreement provides us with the option to interrupt sales to ENAP periodically if conditions in the export markets allow for more competitive price levels. While the agreement renews automatically on an annual basis, we typically revise the agreement every year to reflect changes in the global oil market and make certain adjustments based on ENAP's expenses related to storage at the Gregorio Terminal. As of the date of this annual report, the renewal of our sales agreement with ENAP is under negotiation.

General commercial conditions of our contract with ENAP have remained stable over time. We deliver the oil we produce in the Fell Block to ENAP at the Gregorio Terminal, where ENAP assumes responsibility for the oil transferred. ENAP owns two refineries in Chile in the north central part of the country and must ship any oil from the Gregorio Terminal to these refineries unless it is consumed locally.

In March 2017, we executed a gas supply agreement with Methanex effective from May 1, 2017, to December 31, 2026. Under the agreement, Methanex commits to purchase up to 400,000 SCM/d of gas produced by us. During 2022, we executed an amendment to increase the purchase commitment up to the total gas produced by GeoPark in Chile.

We gather the gas we produce in several wells through our own flow lines and inject it into several gas pipelines owned by ENAP. The transportation of the gas we sell to Methanex through these pipelines is pursuant to a private contract between Methanex and ENAP. We do not own any natural gas pipelines for the transportation of natural gas.

If we were to lose any one of our key customers in Chile, the loss could temporarily delay production and sale of our oil and gas in Chile. For a discussion of the risks associated with the loss of key customers, See “Item 3. Key Information—D. Risk factors—Risks relating to our business—We sell our natural gas in Chile to a single customer, who has in the past temporarily idled its principal facility” and “—We derive a significant portion of our revenues from sales to a few key customers.”

Brazil

Our production in Brazil consists of natural gas, condensate and crude oil. Natural gas production is sold through a long-term, extendable agreement with Petrobras, which provides for the delivery and transportation of the gas produced in the Manati Field to the EVF gas treatment plant in the State of Bahia. The contract is in effect until delivery of the maximum committed volume or June 2030, whichever occurs first. The contract allows for sales above the maximum committed volume if mutually agreed by both seller and buyer. The price for the gas is fixed in reais and is adjusted annually in accordance with the Brazilian inflation index. In July 2015, we signed an amendment to the existing Gas Sales Agreement with Petrobras that covers 100% of the remaining gas reserves in the Manati Field.

The condensate produced in the Manati Field is subject to a condensate purchase agreement with Petrobras, pursuant to which Petrobras has committed to purchase all of our condensate production in the Manati Field, but only in the amounts that we produce, without any minimum or maximum deliverable commitment from us. The agreement is valid through December 31, 2023, and can be renewed upon an amendment signed by Petrobras and the seller.

Ecuador

Ecuador has a well-developed crude oil market with broad access to international markets and an extensive pipeline transportation system. Our oil production, which began in 2022, is transported through the Ecuadorean pipeline system, with Esmeraldas as the delivery point, and 100% of our sales are exported on a competitive basis to industry leading participants including traders and other producers. The oil price is linked to Brent and adjusted by a differential that varies month to month and resembles Oriente crude reference price.

Corporate

GeoPark Limited, our holding company incorporated under the laws of Bermuda, has entered into a crude purchase agreement with an oil producer in the Putumayo Basin. The volumes purchased are transported and exported alongside our Putumayo Basin production. Sales of this crude oil purchased from third parties accounted for 1% of our consolidated revenue in 2022.

Significant Agreements

Colombia

E&P contracts

We have entered into E&P contracts granting us the right to explore and operate, as well as working interests in twenty three blocks in Colombia. These E&P contracts are generally divided into two periods: (1) the exploration period, which may be subdivided into various exploration phases and (2) the exploitation period, determined on a per-area basis and beginning on the date we declare an area to be commercially viable. Commercial viability is determined upon the completion of a specified evaluation program or as otherwise agreed by the parties to the relevant E&P contract. The exploitation period for an area may be extended until such time as such area is no longer commercially viable and certain other conditions are met.

Pursuant to our E&P contracts, we are required, as are all oil and gas companies undertaking exploratory and production activities in Colombia, to pay a royalty to the Colombian government based on our production of hydrocarbons, as of the time a field begins to produce. Under Law 756 of 2002, as modified by Law 1530 of 2012, the royalties we must pay in connection with our production of light and medium oil are calculated on a field-by-field basis. See Note 33.1 to our Consolidated Financial Statements.

Additionally, in the event that an exploitation area has produced amounts in excess of an aggregate amount established in the E&P contract governing such area, the ANH is entitled to receive a "windfall profit", to be paid periodically, calculated pursuant to such E&P contract.

In each of the exploration and exploitation periods, we are also obligated to pay the ANH a subsoil use fee. During the exploration period, this fee is scaled depending on the contracted acreage. During the exploitation period, the fee is assessed on the amount of hydrocarbons produced, multiplied by a specified dollar amount per barrel of oil produced or thousand cubic feet of gas produced. Further, the ANH has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the relevant E&P contract.

Our E&P contracts are generally subject to early termination for a breach by the parties, a default declaration, application of any of the contract's unilateral termination clauses, ANH regulation or termination clauses mandated by Colombian law. Anticipated termination declared by the ANH results in the immediate enforcement of monetary guaranties against us and may result in an action for damages by the ANH. Pursuant to Colombian law, if certain conditions are met, the anticipated termination declared by the ANH may also result in a restriction on the ability to engage contracts with the Colombian government during a certain period. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Our contracts in obtaining rights to explore and develop oil and natural gas reserves are subject to contractual expiration dates and operating conditions, and our CEOPs, E&P contracts, production sharing agreements and concession agreements are subject to early termination in certain circumstances."

<u>*Eastern Llanos Basin:*</u>

Llanos 34 Block E&P contract. Pursuant to an E&P contract between Unión Temporal Llanos 34 (a consortium between Ramshorn and Winchester Oil and Gas— now GeoPark Colombia S.A.S.) and the ANH that became effective as of March 13, 2009 ("Llanos 34 Block E&P contract"), Unión Temporal Llanos 34 was granted the right to explore and operate the Llanos 34 Block, and Winchester Oil and Gas and Ramshorn were granted a 40% and a 60% working interest, respectively, in the Llanos 34 Block. We were also granted the right to operate the Llanos 34 Block. As of the date of this annual report, the members of the Unión Temporal Llanos 34 are GeoPark Colombia S.A.S. with 45%, and Verano Limited with 55% working interest.

On September 19, 2019, the additional exploration period of the Llanos 34 Block E&P contract ended (the E&P contract provides a 1-year Evaluation Program after a discovery declaration). As of the date of this annual report, the Guaco Evaluation Program is still ongoing. The Llanos 34 Block E&P contract also provides a 24-year exploitation period for each production area, beginning on the date of a commercial declaration. The exploitation period may be extended for periods of up to 10 years at a time if certain conditions are met and subject to ANH approval. As of the date of this annual report there are production areas for the Max, Túa, Tarotaro, Tigana, Jacana, Chachalaca, Tilo, Chiricoca and Jacamar fields.

Pursuant to the Llanos 34 Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the Llanos 34 Block. See Note 33.1 to our Consolidated Financial Statements.

Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Llanos 34 Block E&P contract. The ANH also has an additional economic right equivalent to 1% of production, net of royalties.

In accordance with the Llanos 34 Block E&P contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula. See Note 33.1 to our Consolidated Financial Statements.

Llanos 32 Block. We have a 12.5% working interest in the Llanos 32 Block. Verano Energy is the operator of this block and has an 87.5% working interest. On February 20, 2022, the exploratory period ended. Economic rights to the ANH are similar to Llanos 34 Block's.

Abanico Block. In October 1996, Ecopetrol and Explotaciones CMS Nomeco Inc. entered into the Abanico Block association contract. Pacific Rubiales Energy is the operator of, and has a 100% working interest in, the Abanico Block. We do not maintain a direct working interest in the Abanico Block, but rather have a 10% economic interest in the net revenues from the block pursuant to a joint operating agreement initially entered into with Kappa Resources Colombia Limited (now Pacific, who subsequently assigned its participation interest to Cespa de Colombia S.A., who then assigned the interest to Explotaciones CMS Oil & Gas), Maral Finance Corporation and Getionar S.A.

Llanos 86, Llanos 87, Llanos 104, Llanos 123 and Llanos 124 Blocks. We and Hocol (a subsidiary of Ecopetrol), each with fifty percent (50%) working interest, executed E&P contracts over these blocks in 2019, as a result of the Permanent Competitive Process launched by ANH. We are the operator of these contracts that are in exploratory phase 1.

In these E&P contracts, we are required to pay subsurface rights to the ANH, calculated based on the total acreage of the blocks, or the remaining area if in case of relinquishment had taken place. There is also an additional annual 25% markup of said subsurface rights payable as a fee for institutional development and technological transfer.

Upon production, and in addition to legal royalties, the ANH is entitled to receive a percentage of total production net of royalties, at the delivery point (multiplied by a factor set in the contract and based on international oil prices). That percentage is 3% in the Llanos 87 E&P contract, 2% in the Llanos 86 and Llanos 104 E&P contracts and 1% in the Llanos 123 and Llanos 124 E&P contracts.

There is an additional 5-10% share payable to the ANH applicable upon extensions to the production period and when the accumulated gross aggregate production of the area of the contract exceeds 5 million barrels and the WTI exceeds a defined price. ANH becomes entitled to an additional share on production in accordance with a formula set in the contract.

Llanos 94 Block. On July 24, 2019 the E&P contract was awarded to Parex Energy as a result of the Permanent Competitive Process launched by ANH in 2019. This contract is in its exploratory phase 1. We acquired a 50% working interest from Parex and obtained ANH's approval to such transfer in May, 2020.

In the Llanos 94 E&P contract, we are required to pay subsurface rights to the ANH, calculated based on the total acreage of the blocks, or the remaining area if relinquishment had taken place. There is also an additional annual 25% markup of said subsurface rights payable as a fee for institutional development and technological transfer.

Upon production, and in addition to legal royalties, the ANH is entitled to receive 2% of total production net of royalties, at the delivery point (multiplied by a factor set in the contract and based on international oil prices).

There is an additional 5-10% share payable to the ANH applicable upon extensions to the production period and when the accumulated gross aggregate production of the area of the contract exceeds 5 million barrels and the WTI exceeds a defined price. ANH becomes entitled to an additional share on production in accordance with a formula set in the contract.

CPO-5 Block E&P contract. On December 26, 2008, the E&P contract was executed between ONGC Videsh, as operator and the ANH as a result of the Competitive Process "Ronda Colombia 2008". We hold a 30% working interest since the acquisition of Amerisur. The contract is in phase 2 of the exploration period as of the date of this annual report. There are two existing commercial fields called Mariposa and Indico field. Indico was declared commercially viable on August 19, 2021.

Pursuant to the CPO-5 Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the CPO-5 Block.

Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the CPO-5 Block E&P contract. The ANH also has an additional economic right equivalent to 23% of production, net of royalties.

In accordance with the CPO-5 Block E&P contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula.

CPO-4-1 Block. On January 18, 2022, the E&P contract was executed between Parex Energy and the ANH as a result of the Permanent Competitive Process launched by ANH in 2019. On April 29, 2022, an amendment to the E&P contract was executed, whereby the ANH approved the assignment of a 50% non-operated working interest to us. As of the date of this annual report, this contract is in exploratory phase 1.

Pursuant to CPO-4-1 Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the CPO-4-1 Block.

Additionally, we are required to pay a surface and subsoil usage fee to the ANH. We are required to comply with the VEE (economic value for exclusivity) equivalent to the commitments for the exploratory period; however, if we do not perform such commitments, the VEE amount calculated as provided in the CPO-4-1 E&P contract, must be paid to the ANH. The ANH also has an additional economic right equivalent to 1% of production, net of royalties.

In accordance with the CPO-4-1 Block E&P contract, when the accumulated production of the area of the contract, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, we should deliver to ANH a share of the production net of royalties in accordance with an established formula.

Magdalena Basin:

VIM-3 Block. On July 23, 2014, we were awarded an exploratory license during the 2014 Colombia Bidding Round, carried out by the ANH. The VIM-3 Block is located in the Lower Magdalena Basin. In 2018, we filed a request before the ANH to terminate the E&P contract due to environmental restrictions in the block. These restrictions became apparent once the National Authority of Environmental Licenses issued the environmental license. As of the date of this annual report, the termination was approved by the ANH and the final liquidation of the contract is pending.

Putumayo Basin:

Andaquies Block E&P contract. We are the operator of and have a 100% working interest in the Andaquies. As of the date of this annual report, termination of the E&P contract has been approved by the ANH and the final liquidation of the contract is pending.

Coati Block E&P contract. We are the operator of and have a 100% working interest in the Coati Block. The Coati Block is divided into two areas: an exploration area in phase 3 of the exploration period, suspended due to Force Majeure Events (Prior Consultations); and an evaluation area, declared on September 2006, by the former operator in the southern part of the Block for the Temblon wells (Temblon Evaluation Program), which includes the completion and evaluation of the Coatí-1 well.

Pursuant to the Coati Block E&P contract and applicable law, we are required to pay a royalty of 23% to the ANH based on hydrocarbons produced in the block.

Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Coati Block E&P contract.

In accordance with the Coati Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, we should deliver to ANH a share of the production net of royalties in accordance with an established formula.

Mecaya Block E&P contract. We are the operator of and have a 50% working interest in the Mecaya Block. Sierracol Energy is the owner of the remaining 50% working interest in the contract. As of the date of this annual report, the contract is in unified phases 1 and 2 of the exploration period, and it is suspended due to Force Majeure Events (Prior Consultations).

Pursuant to the Mecaya Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the Mecaya Block.

Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Mecaya Block E&P contract.

In accordance with the Mecaya Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula.

Platanillo Block E&P contract. We are the operator of and have a 100% working interest in the Platanillo Block. On September 11, 2009, we began commercial exploitation.

Pursuant to the Platanillo Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the Platanillo Block.

Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Platanillo Block E&P contract.

In accordance with the Platanillo Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula.

Putumayo 8 Block E&P contract. We are the operator of and have a 50% working interest in the Putumayo 8 Block. Sierracol Energy is the owner of the remaining 50% working interest. The contract is in unified phases 1 and 2 of the exploration period.

Pursuant to the Putumayo 8 Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the block.

Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Putumayo 8 Block E&P contract. The ANH also has an additional economic right equivalent to 2% of production, net of royalties.

In accordance with the Putumayo 8 Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula.

Putumayo 9 Block E&P contract. We are the operator of and have a 50% working interest in the Putumayo 9 Block. Sierracol Energy is the owner of the remaining 50% working interest. As of the date of this annual report, the contract is in phase 1 of the exploration period, which is suspended since June 25, 2019, due to the occurrence of a Force Majeure event (issuance of the Municipal Agreement which prohibits the execution of hydrocarbons exploration and production activities in Puerto Guzmán Municipality).

Pursuant to the Putumayo 9 Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the block.

Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Putumayo 9 Block E&P contract. The ANH also has an additional economic right equivalent to 18% of production, net of royalties.

In accordance with the Putumayo 9 Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula.

Putumayo 12 Block E&P contract. We are the operator of and have a 60% working interest in the Putumayo 12 Block. Pluspetrol Colombia Corporation ("Pluspetrol") is the owner of the remaining 40% working interest. As of the date of this annual report, termination of the E&P contract has been approved by the ANH and the final liquidation of the contract is pending.

Putumayo 14 Block E&P contract. We are the operator of and have a 100% working interest in the Putumayo 14 Block. On March 10, 2022, we submitted to the ANH a request to withdraw from the PUT-14 E&P contract and transfer the pending commitments to the Platanillo and CPO-5 Blocks. Once total investment is reached through such transfers, ANH will proceed with the contract's termination. As of the date of this annual report, part of the abovementioned investment has already been incurred and the ANH approval of the fulfillment is pending.

Putumayo 30 Block E&P contract. We are the operator of and have a 100% working interest in the Putumayo 30 Block. On February 23, 2021, we submitted to the ANH our request to withdraw from to the E&P contract and transfer the remaining commitments to other E&P contracts. The ANH approved the request and the remaining investment was transferred to Llanos 34 Block and Platanillo Block. As of the date of this annual report, the E&P contract is in process of liquidation.

Putumayo 36 Block E&P contract. We are the operator of and have a 50% working interest in the Putumayo 36 Block. Sierracol is the owner of the remaining 50% working interest. The contract is in preliminary phase, which is suspended since April 1, 2020 due to the occurrence of a Force Majeure Event (issuance of the Municipal Agreement which prohibits the execution of hydrocarbons exploration and production activities in Puerto Guzmán Municipality).

Pursuant to the Putumayo 36 Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the block.

Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Putumayo 36 Block E&P contract, and the payment of 25% of the Economic Right for the use of the subsoil for institutional strengthening and Technology Transfer.

The ANH also has an additional economic right equivalent to 1% of production, net of royalties.

In accordance with the Putumayo 36 Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula.

Tacacho Block E&P contract. We are the operator of and have a 50% working interest in the Tacacho Block. Sierracol Energy is the owner of the remaining 50% working interest. The contract is in phase 1 of the exploration period, which is currently suspended due to the occurrence of force majeure events related with social and public order conditions of the area.

Pursuant to the Tacacho Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the block. Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Tacacho Block E&P contract. In accordance with the Tacacho Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula.

On September 21, 2022, we submitted to the ANH a request for termination of the E&P contract. As of the date of this annual report, the request is under review by the ANH.

Terecay Block E&P contract. We are the operator of and have a 50% working interest in the Terecay Block. Sierracol Energy is the owner of the remaining 50% working interest. The contract is in phase 1 of the exploration period, which is currently suspended due to the occurrence of force majeure events related with social and public order conditions of the area.

Pursuant to the Terecay Block E&P contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the block. Additionally, we are required to pay a subsoil use fee to the ANH. The ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Terecay Block E&P contract. In accordance with the Terecay Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula.

On September 21, 2022, we submitted to the ANH a request for termination of the E&P contract. As of the date of this annual report, the request is under review by the ANH.

Overriding Royalty Agreements

We are obligated to pay an overriding royalty of 4% and 2.5%, respectively, to the previous owners of the Llanos 34 and CPO-5 Blocks, based on the production and sale of hydrocarbons discovered in the blocks. During 2022, the Group has accrued US$34.0 million in relation to these overriding royalty agreements. Furthermore, there are overriding royalty agreements in place from 1.2% to 8.5% of the net production in the Andaquies, Coati, Mecaya, PUT-8, PUT-9, Tacacho and Terecay Blocks. Since they were exploratory blocks with no production during 2022, these agreements had no impact on our results.

Chile

CEOPs

Currently, we have four CEOPs in effect with Chile, one for each of the blocks in which we operate, which grant us the right to explore and exploit hydrocarbons in these blocks, determine our working interests in the blocks and appoint the operator of the blocks. These CEOPs are divided into two phases: (1) an exploration phase, which is divided into two or more exploration periods, and which begins on the effectiveness date of the relevant CEOP, and (2) an exploitation phase, which is determined on a per-field basis, commencing on the date we declare a field to be commercially viable and ending with the term of the relevant CEOP. In order to transition from the exploration phase to an exploitation phase, we must declare a discovery of hydrocarbons to the Ministry of Energy. This is a unilateral declaration, which grants us the right to test a field for a limited period of time for commercial viability. If the field proves commercially viable, we must make a further unilateral declaration to the Ministry of Energy. In the exploration phase, we are obligated to fulfill a minimum work commitment, which generally includes the drilling of wells, the performance of 2D or 3D seismic surveys, minimum capital commitments and guaranties or letters of credit, as set forth in the relevant CEOP. We also have relinquishment obligations at the end of each period in the exploration phase in respect of those areas in which we have not made a declaration of discovery. We can also voluntarily relinquish areas in which we have not declared discoveries of hydrocarbons at any time, at no cost to us. In the exploitation phase, we generally do not face formal work commitments, other than the development plans we file with the Chilean Ministry of Energy for each field declared to be commercially viable.

Our CEOPs provide us with the right to receive a monthly remuneration from Chile, payable in petroleum and gas, based either on the amount of petroleum and gas production per field or according to Recovery Factor, which considers the ratio of hydrocarbon sales to total cost of production (capital expenditures plus operating expenses). Pursuant to Chilean law, the rights contained in a CEOP cannot be modified without consent of the parties.

Our CEOPs are subject to early termination in certain circumstances, which vary depending upon the phase of the CEOP. During the exploration phase, Chile may terminate a CEOP in circumstances including a failure by us to comply with minimum work commitments at the termination of any exploration period, or a failure to communicate our intention to proceed with the next exploration period 30 days prior to its termination, a failure to provide the Chilean Ministry of Energy the performance bonds required under the CEOP, a voluntary relinquishment by us of all areas under the CEOP or a failure by us to meet the requirements to enter into the exploitation phase upon the termination of the exploration phase. In the exploitation phase, Chile may terminate a CEOP if we stop performing any of the substantial obligations assumed under the CEOP without cause and do not cure such nonperformance pursuant to the terms of the concession, following notice of breach from the Chilean Ministry of Energy. Additionally, Chile may terminate the CEOP due to force majeure circumstances (as defined in the relevant CEOP). If Chile terminates a CEOP in the exploitation phase, we must transfer to Chile, free of charge, any productive wells and related facilities, provided that such transfer does not interfere with our abandonment obligations and excluding certain pipelines and other assets. Other than as provided in the relevant CEOP, Chile cannot unilaterally terminate a CEOP without due compensation. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Our contracts in obtaining rights to explore and develop oil and natural gas reserves are subject to contractual expiration dates and operating conditions, and our CEOPs, E&P contracts, production sharing agreements and concession agreements are subject to early termination in certain circumstances."

Fell Block CEOP. On November 5, 2002, we acquired a percentage of rights and interests of the CEOP for the Fell Block with Chile, or the Fell Block CEOP, and on May 10, 2006, we became the sole owners, with 100% of the rights and interest in the Fell Block CEOP. Chile had originally entered into a CEOP for the Fell Block with ENAP and Cordex Petroleum Inc., or Cordex, on April 29, 1997, which had an effective date of August 25, 1997. The Fell Block CEOP grants us the exclusive right to explore and exploit hydrocarbons in the Fell Block and has a term of 35 years, beginning on the effective date. The Fell Block CEOP provided for a 14-year exploration period, composed of numerous phases that ended in 2011, and an up-to-35-year exploitation phase for each field.

The Fell Block CEOP provides us with a right to receive a monthly retribution from Chile payable in petroleum and gas, based on the following per-field formula: 95% of the oil production sold in the field, for production sold of up to 5,000 bopd, ring fenced by field, and 97% of gas production sold in the field, for production sold of up to 882.9 mmcfpd. In the event that we exceed these levels of production sold, our monthly retribution from Chile will decrease based on a sliding scale set forth under the Fell Block CEOP to a maximum of 50% of the oil and 60% of the gas that we sell per field.

TDF Blocks CEOPs. After an international bidding process led by ENAP and the Chilean Ministry of Energy, in March and April 2012, we, together with ENAP, signed 3 new CEOPs for the Isla Norte, Campanario and Flamenco Blocks, all of them located in Tierra del Fuego ("TDF"), Magallanes region. Our working interest is 60% in Isla Norte and 50% in Campanario and Flamenco Blocks. The CEOPs have a term of 32 years, with an initial exploration phase which last for up to 10 years, including a first exploration period of 3 years in which we are committed to developing several exploration activities including 1,500 sq. km. of 3D seismic registration, and the drilling of 21 exploratory wells.

The hydrocarbon discoveries opened up an exploitation phase that lasts up to 25 years. We discovered hydrocarbon fields in the 3 blocks, starting in 2013 in the Flamenco Block, and in 2014 in both Campanario and Isla Norte Blocks. The CEOPs provide us with a right to receive a remuneration payable by means of a fraction of the production sold, which in the TDF Blocks is based on a formula depending on the recovery of the total accumulated expenses incurred (capital expenditure plus operational expenditure plus administrative and general expenses). While the recovery factor is less than 1.0, the remuneration is 95% of the hydrocarbons sold, either oil or gas. If the recovery factor surpasses 1.0, a formula applies reducing gradually the remuneration fraction to a minimum of 75% when the recovery factor is 2.5 times the total accumulated expenses.

Brazil

Overview of concession agreements

The Brazilian oil and gas industry is governed mainly by the Brazilian Petroleum Law, which provides for the granting of concessions to operate petroleum and gas fields in Brazil, subject to oversight by the ANP. A concession agreement is divided into two phases: (1) exploration and (2) development and production. The exploration phase consists of one exploratory period that begins on the date of execution of the concession agreement, which can last from three to eight years (subject to earlier termination upon the total return of the concession area or the declaration of commercial viability with respect to a given area), while the development and production phase, which begins for each field on the date a declaration of commercial viability is submitted to the ANP, can last up to 27 years. Upon each declaration of commercial viability, a concessionaire must submit to the ANP a development plan for the field within 180 days. The concessions may be renewed for an additional period equal to their original term if renewal is requested with at least 12 months' notice and provided that a default under the concession agreement has not occurred and is then continuing. Even if obligations have been fulfilled under the concession agreement and the renewal request was appropriately filed, renewal of the concession is subject to the discretion of the ANP.

The main terms and conditions of a concession agreement are set forth in Article 43 of the Brazilian Petroleum Law, and include: (1) definition of the concession area; (2) validity and terms for exploration and production activities; (3) conditions for the return of concession areas; (4) guarantees to be provided by the concessionaire to ensure compliance with the concession agreement, including required investments during each phase; (5) penalties in the event of noncompliance with the terms of the concession agreement; (6) procedures related to the assignment of the agreement; and (7) rules for the return and vacancy of areas, including removal of equipment and facilities and the return of assets. Assignments of participation interests in a concession are subject to the approval of the ANP, and the replacement of a performance guarantee is treated as an assignment.

The main rights of the concessionaires (including us in our concession agreements) are: (1) the exclusive right of drilling and production in the concession area; (2) the ownership of the hydrocarbons produced; (3) the right to sell the hydrocarbons produced; and (4) the right to export the hydrocarbons produced. However, a concession agreement set forth that, in the event of a risk of a fuel supply shortage in Brazil, the concessionaire must fulfill the needs of the domestic market. In order to ensure the domestic supply, the Brazilian Petroleum Law granted the ANP the power to control the export of oil, natural gas and oil products.

Among the main obligations of the concessionaire are: (1) the assumption of costs and risks related to the exploration and production of hydrocarbons, including responsibility for environmental damages; (2) compliance with the requirements relating to acquisition of assets and services from domestic suppliers; (3) compliance with the requirements relating to execution of the minimum exploration program proposed in the winning bid; (4) activities for the conservation of reservoirs; (5) periodic reporting to the ANP; (6) payments for government participation; and (7) responsibility for the costs associated with the deactivation and abandonment of the facilities in accordance with Brazilian law and best practices in the oil industry.

A concessionaire is required to pay to the Brazilian government the following:

- a license fee;
- rent for the occupation or retention of areas;
- a special participation fee;
- royalties; and
- taxes.

Rental fees for the occupation and maintenance of the concession areas are payable annually. For purposes of calculating these fees, the ANP takes into consideration factors such as the location and size of the relevant concession, the sedimentary basin and the geological characteristics of the relevant concession.

A special participation fee is an extraordinary charge that concessionaires must pay in the event of obtaining high production volumes and/or profitability from oil fields, according to criteria established by applicable regulations, and is payable on a quarterly basis for each field from the date on which extraordinary production occurs. This participation fee, whenever due, varies between 0% and 40% of net revenues depending on (1) the volume of production and (2) whether the concession is onshore or in shallow water or deep water. Under the Brazilian Petroleum Law and applicable regulations issued by the ANP, the special participation fee is calculated based on the quarterly net revenues of each field, which consist of gross revenues calculated using reference prices established by the ANP (reflecting international prices and the exchange rate for the period) less:

- royalties paid;
- investment in exploration;
- operational costs; and
- depreciation adjustments and applicable taxes.

The Brazilian Petroleum Law also requires that the concessionaire of onshore fields pay to the landowners a special participation fee that varies between 0.5% to 1.0% of the net operational income originated by the field production.

BCAM-40 Concession Agreement. On August 6, 1998, the ANP and Petrobras executed the concession agreement governing the BCAM-40 Concession, or the BCAM-40 Concession Agreement, following the first round of bidding, referred to as Bid Round Zero, under the regime established by the Brazilian Petroleum Law. The exploitation phase will end in November 2029. On September 11, 2009, Petrobras announced the termination of BCAM-40 Concession's exploration phase and the return of the exploratory area of the concession to the ANP, except for the Manati Field.

Under the BCAM-40 Concession Agreement, the ANP is entitled to a monthly royalty payment equal to 7.5% of the production of oil and natural gas in the concession area. In addition, in case the special participation fee of 10% shall be applicable for a field in any quarter of the calendar year, the concessionaire is obliged to make qualified research and development investments equivalent to one percent of the field's gross revenue. Area retention payments are also applicable under the concession agreement. We acquired Rio das Contas' 10% participation interest in the BCAM-40 Concession on March 31, 2014. On November 22, 2020, we signed an agreement to sell our 10% participation interest in the Manati Block. The transaction was subject to certain conditions that should have been met before March 31, 2022. As of March 31, 2022, the required conditions were not met and we decided not to extend this deadline. As a result, we continue to own our 10% interest in the block.

Rounds 11, 12, 13 and 14 Concession Agreements.

Under the Rounds 11, 12, 13 and 14 Concession Agreements, the ANP is entitled to a monthly royalty corresponding to up to 10% of the production of oil and natural gas in the concession area, in addition to the special participation fee described above, the payment for the occupation of the concession area of approximately R$7,600 per year and the payment to the owners of the land of the concession equivalent to one percent of the oil and natural gas produced in the concession area.

During bidding, a work program offer is made in the form of work units and the ANP asks for a guarantee of a monetary amount proportional to the offered units. However, depending on the work performed by the operator, the actual work program investment might have a different value to the guaranteed value.

Overview of consortium agreements

A consortium agreement is a standard document describing consortium members' respective percentages of participation and appointment of the operator. It generally provides for joint execution of oil and natural gas exploration, development and production activities in each of the concession areas. These agreements set forth the allocation of expenses for each of the parties with respect to their respective participation interests in the concession. The agreements are supplemented by joint operating agreements, which are private instruments that typically regulate the aggregation of funds, the sharing of costs, mitigation of operational risks, preemptive rights and the operator's activities.

An important characteristic of the consortia for exploration and production of oil and natural gas that differs from other consortia (Article 278, paragraph 1, of the Brazilian Corporate Law) is the joint liability among consortium members as established in the Brazilian Petroleum Law (Article 38, item II).

BCAM-40 Consortium Agreement

On January 14, 2000, Petrobras, Queiroz Galvão Perfurações (now Enauta) and Petroserv entered into a consortium agreement, or the BCAM-40 Consortium Agreement, for the performance of the BCAM-40 Concession Agreement. Petrobras is the operator of the BCAM-40 concession, with a 35% participation interest. Enauta, PetroRio and GeoPark Brazil have a 45%, 10% and 10% participation interest, respectively. The BCAM-40 Consortium Agreement has a specified term of 40 years, terminating on January 14, 2040 and, at the time the obligations undertaken in the agreement are fully completed, the parties will have the right to terminate it. The BCAM-40 Concession consortium has also entered into a joint operating agreement, which sets out the rights and obligations of the parties in respect of the operations in the concession.

Petrobras Natural Gas Purchase Agreement

Enauta, GeoPark Brazil, PetroRio and Petrobras are party to a natural gas purchase agreement providing for the sale of natural gas by Enauta, GeoPark Brazil and PetroRio to Petrobras, in an amount of 812 billion cubic feet ("bcf") over the term of agreement. The Petrobras Natural Gas Purchase Agreement is valid until the earlier of Petrobras' receipt of this total contractual quantity or June 30, 2030. The agreement may not be fully or partially assigned except upon execution of an assignment agreement with the written consent of the other parties, which consent may not be unreasonably withheld provided that certain prerequisites have been met.

The agreement provides for the provision of "daily contractual quantities" to Petrobras peaking at 170.3 mmcfd in 2016 and progressively dropping until 2030. The parties may agree to lower volumes as dictated by Manati Field's depletion. Pursuant to the agreement, the base price is denominated in reais and is adjusted annually for inflation pursuant to the general index of market prices (IGPM). Additionally, the gas price applicable on a given day is subject to reduction as a result of the gas quantity acquired by Petrobras above the volume of the annual TOP commitment (85% of the daily contracted quantity) in effect on such day. The Petrobras Natural Gas Purchase Agreement provides that all of the Manati Field's daily production be sold to Petrobras.

Argentina

Overview of exploration permits

Our exploration permits grant to us and our partners the exclusive right to explore for hydrocarbons and declare a commercial discovery within the acreage of our permits. Our exploration permits are made up of three subperiods, each lasting 3, 2 and 1 year(s), respectively, plus an extension period of up to 5 years.

We are bound to pursue specific minimum work or investment commitments during each of the subperiods of each exploration permit. Such exploration works are valued in work units assigned to each particular type of work under the applicable bidding conditions.

Work and investment programs for the permits are required to be assured by issuing a performance bond for the value of the committed work plan.

Under the terms of our exploration permits and concession agreements, we are entitled to our proportionate share of the hydrocarbons production lifted from each block. We pay annual surface rental fees established under Hydrocarbons Law 17,319 (“Hydrocarbons Law”) and Resolution 588/98 of the Argentine Secretariat of Energy and Decree 1454/2007, and certain landowner fees.

Our Argentine exploration permits have no change of control provisions, though any assignment of these concessions is subject to the prior authorization by the executive branch of the Province of Mendoza and rights of first refusal in favor of our partners and EMESA, in the case of the Puelen permit. Each of these permits or future concessions can be terminated for default in payment obligations and/or breach of material statutory or regulatory obligations. We are subject to the obligation to relinquish at least 50% of the acreage of each exploration permit at the end of each exploration subperiod. We may also voluntarily relinquish acreage to the provincial authorities.

Our Argentine exploration permits are governed by the laws of Argentina and the resolution of any disputes must be sought in the Mendoza Provincial Courts.

If and when we make a commercial discovery in one or more of our exploration permits, we will have the right to request and obtain an exploitation concession to produce hydrocarbons in the block for 25 years, with an optional extension of up to 10 years. We also receive the right to be granted a 35-year oil transport concession to build and make use of pipelines or other transport facilities beyond the boundaries of the concession.

Additionally, oil and gas producers in Argentina must grant a privilege to the domestic market to the detriment of the export market, including hydrocarbon export restrictions, domestic price controls, export duties and domestic market supplier obligations.

Ecuador

Production sharing contracts

We entered into two production sharing contracts with the Ministry of Energy and Mines. While we are the operators in the Espejo Block, Frontera operates the Perico Block. The production sharing contracts in Ecuador are generally divided into two stages: (i) an exploration period of 4 years, which may be extended to 6 years; and (ii) a production period of 20 years. The exploitation or production period commences upon Governmental approval of the exploitation and development plan of a commercial field (although early production during the exploration period is allowed). The extension of the production period requires entering into an amendment to the contract with the Government of Ecuador, which may imply revision of contractual conditions.

In the Espejo and Perico production sharing contracts, production is measured and distributed among the contractor and the Government at the delivery point where a production sharing formula is applied based on international oil prices of the Oriente marker in the previous month and the offer made as base point in each tender. No further royalties apply. In addition, we are obliged to make a yearly payment of US$24,000 as compensation for the use of water and natural construction materials, which increases to US$60,000 during the production stage. Furthermore, there is an institutional development fee of US$100,000 payable every year.

Title to properties

In each of the countries in which we operate, the state is the exclusive owner of all hydrocarbon resources located in such country and has full authority to determine the rights, royalties or compensation to be paid by private investors for the exploration or production of any hydrocarbon reserves. In Chile, the Republic of Chile grants such rights through a CEOP. In Colombia, the Republic of Colombia grants such rights through E&P contracts or contracts of association. In Brazil, the Federative Republic of Brazil grants such rights pursuant to concession agreements. In Argentina, the Argentine Republic grants such rights through exploitation concessions. In Ecuador, our rights were granted through production sharing contracts. See “Item 3. Key Information—D. Risk factors—Risks relating to the countries in which we operate—Oil and natural gas companies in Colombia, Chile, Brazil, Argentina and Ecuador do not own any of the oil and natural gas reserves in such countries.” Other than as specified in this annual report, we believe that we have satisfactory rights to exploit or benefit economically from the oil and gas reserves in the blocks in which we have an interest in accordance with standards generally accepted in the international oil and gas industry. Our CEOPs, E&P contracts, contracts of association, exploitation concessions and concession agreements are subject to customary royalty and other interests, liens under operating agreements and other burdens, restrictions and encumbrances customary in the oil and gas industry that we believe do not materially interfere with the use of or affect the carrying value of our interests. See “Item 3. Key Information—D. Risk factors—Risks relating to our business—We are not, and may not be in the future, the sole owner or operator of all of our licensed areas and do not, and may not in the future, hold all of the working interests in certain of our licensed areas. Therefore, we may not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and, to an extent, any non-wholly owned, assets.”

Our customers

In Colombia, the oil and gas production was sold to three clients that concentrate 97% of the Colombian subsidiaries revenue (90% of our total consolidated revenue) for the year ended December 31, 2022. In Chile, our primary customers are ENAP and Methanex. As of December 31, 2022, ENAP purchased all of our Chilean oil and condensate production and Methanex purchased all of our natural gas production in Chile, and together represented 3% of our total revenue for the year ended December 31, 2022. In Brazil, all of our hydrocarbons in Manati were sold to Petrobras and represented 2% of our total revenue for the year ended December 31, 2022. In Ecuador, 100% of our sales (1% of our total revenue for the year ended December 31, 2022) were exported on a competitive basis to industry leading participants including traders and other producers. We managed the counterparty credit risk associated to sales contracts by limiting payment terms offered to minimize the exposure.

Seasonality

Although there is some historical seasonality to the prices that we receive for our production, the impact of such seasonality has not been material. Seasonality has also not played a significant role in our ability to conduct our operations, including drilling and completion activities.

Our competition

The oil and gas industry is competitive, and we may encounter strong competition from other independent operators and from major state-owned oil companies in acquiring and developing licenses in the countries where we operate or plan to operate.

Many of these competitors have financial and technical resources and personnel substantially larger than ours. As a result, our competitors may be able to pay more for desirable oil and natural gas assets, or to evaluate, bid for and purchase a greater number of licenses than our financial or personnel resources will permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful wells, sustained periods of volatility in financial and commodities markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which may adversely affect our competitive position. See “Item 3. Key Information—D. Risk factors—Risks relating to our business—Competition in the oil and natural gas industry is intense, which makes it difficult for us to attract capital, acquire properties and prospects, market oil and natural gas and secure trained personnel.”

We may also be affected by competition for drilling rigs and the availability of related equipment. Higher commodity prices generally increase the demand for drilling rigs, supplies, services, equipment and crews, and can lead to shortages of, and increasing costs for, drilling equipment, services and personnel. Shortages of, or increasing costs for, experienced drilling crews and equipment and services could restrict our ability to drill wells and conduct our operations.

Health, safety and environmental matters

General

Our corporate HSE commitment governs our actions, in accordance with the legal framework, industry best practices and international standards in terms of socio-environmental, health and safety performance. We work closely with our suppliers and contractors to transfer the best HSE practices throughout our value chain and extend our responsibility towards the environment, with binding contractual agreements, monthly safety and environmental performance evaluations, annual compliance evaluations and the construction of capacities and competencies necessary to be in line with our health, safety, and environmental commitment.

We have an environmental management and feasibility strategy that allows us to guarantee the development of plans and actions that ensure respect and protection of the environment in the territories where we operate.

In each of the countries where we operate, we ensure compliance with applicable health, safety and environmental requirements. All our operations have the environmental licenses and permits required under the applicable legislation, which are derived from the development of environmental studies with citizen participation for the definition of management measures and impact mitigation.

Our Environmental Management System (EMS) certified under the ISO standard: 14001:2015 for our operations in Colombia, defines programs for the integral management of water resources; solid and liquid waste management; atmospheric emissions and energy; biodiversity and ecosystem services and training and awareness regarding the protection of the environment for employees and suppliers. In addition, it defines the roles and responsibilities of management regarding to the performance of our environmental issues.

Although we do not have a certified EMS in countries such as Ecuador and Chile, we have implemented the main programs contemplated by our corporate environmental commitment.

Our corporate environmental commitment is mainly based on the management of the following issues:

Integral water management

We recognize water as a strategic resource and axis of sustainable development in the territories. For this reason, we implement initiatives and strategies for saving and efficient use of the resource, and we focus our efforts on seeking efficiencies in the operation, on reusing water and on reducing environmental impacts and conflicts associated with water management.

We have an integral water management program that allows us to monitor the information necessary to control its use and consumption, ensure compliance with our environmental permits and take the necessary measures to control the different activities where we use water.

All the waste waters generated in our operations is treated and disposed of in accordance with the environmental licenses.

In 2022, we did not use surface water sources in our permanent operations in Colombia and we did not carry out any type of dumping in surface waterbodies, to avoid any possible conflict with the other users of this resource.

Biodiversity

Through our management, we articulate our efforts to avoid, mitigate and eliminate any impact that may represent a material risk to the biodiversity of the environment where we operate. We recognize the importance of biodiversity in the areas of our interest since the planning stage of our projects. We are committed to avoiding operations in legally protected areas and taking into account biodiversity value and ecosystem services as a driver to design, planning and execute our projects. Ecosystem services are the services that nature provides to the people, such as fresh water, food, medicines, regulation of floods and soil erosion and carbon dioxide capture.

In addition, we compensate for our residual impact on biodiversity and, we participate and promote programs related to the rehabilitation, restoration, and conservation of high value ecosystems through strategic alliances for the conservation of biodiversity.

Climate change

Our response to climate change and our contribution to achieve the goal of sustainable development number 13 of the United Nations is part of the strategy to minimize emissions of Greenhouse Gas (GHG) announced by us in November 2021, following the approval of our board of directors of the voluntary reduction voluntarily goals adopted by us:

- 35-40% GHG emissions intensity reduction of Scope 1 and 2 emissions by 2025;

- 40-60% GHG emissions intensity reduction of Scope 1 and 2 emissions by 2030; and

- net zero Scope 1 and 2 emissions by or before 2050.

All our abovementioned goals are defined against a 2020 baseline.

These goals take into account the execution of some operational and environmental projects. The following projects are the most relevant achieved during 2022 in Colombia:

- the interconnection of the core Llanos 34 Block to Colombia's national grid was a decisive near-term catalyst to improve carbon performance and operational reliability, while reducing cost of energy generation; and

- also in the Llanos 34 Block, a dedicated 10MW solar photovoltaic plant became operational by November 2022.

Medium-term actions include energy efficiency, small-scale renewable projects, reforestation, and afforestation initiatives, among others.

Longer-term actions may include carbon capture, use and storage projects and potential participation in carbon markets.

As of the date of this annual report, we have other ongoing environmental initiatives to mention, such as:

- In Colombia, we continue the execution of an agreement with the Institute of Hydrology, Meteorology and Environmental Studies (IDEAM) for the strengthening and modernization of the hydrometeorological monitoring network of the Orinoquía, in the hydrographic zone of the Meta River, which will contribute to improving water management, comprehensive risk management and adaptation to climate change.

- We developed projects focused on the conservation and protection of ecosystems, implementing initiatives that contribute to the reduction of biodiversity loss, the promotion of conservation of the environment and the stability of ecosystems.

- In 2022 we continue being part of the Putumayo Regional Agreement for Biodiversity and Development, which integrates efforts by the private sector and national and regional entities to preserve the biodiversity and connectivity of this region of the Amazon. As part of this agreement, in 2022, we made an alliance with the von Humboldt Biological Resources Research Institute and the Biodiversity Information System in Colombia to launch the project "Gestión Corporativa para la Naturaleza" to promote the report and use of open data on biodiversity.

- In Colombia, during 2022, we reported over 69,000 biodiversity registrations obtained during the historical environmental studies and monitoring, as a contribution to the open data system of the country.

- In Ecuador, in the canton of Shushufindi, province of Sucumbios, we developed, in coordination with the local and provincial government, a project for the recovery of plant cover in areas of watercourses and estuaries with an ecosystem, landscape and watershed protection approach, in order to improve the natural balance and the biodiversity of the territory.

- We actively participated in initiatives led by national and local governments in the countries where we operate focused on reducing deforestation. In 2022, we contributed by planting or donating more than 34,000 trees, as part of our environmental obligations and voluntary initiatives.

Integral waste management and circular economy

Regarding the proper management of solid waste generated by our activities, we focus our management on the principles of reduce, reuse, recycle and recover. In this way we ensure the mitigation of environmental impacts, while complying with applicable regulations. In 2022, we defined our circular economy strategic plan and the roadmap for its implementation. As part of this plan, we defined the meaning of circular economy for GeoPark, and we also defined our pillars and models.

Spill Management

In 2022, there was one recordable hydrocarbon spill (>=1Bbl uncontained) in our operations in Colombia, related to one barrel spilled in soil and a nearby waterbody. This event was caused by unknown third parties. In corporate terms, we closed the year with an OBS of 0.43 barrels spilled per million barrels produced. This indicator was lower than the goal established for the year.

Our HSE Management System

Our health, safety and environmental management plan is focused on undertaking realistic and practical programs based on recognized world practices. Our emphasis is on building key principles and company-wide ownership and then expanding programs as we continue growing. Our SPEED philosophy and our HSE Plan have been developed with reference to ISO 14001 for environmental management issues, ISO 45000 for occupational health and safety management issues, SA 8000 for social accountability and workers' rights issues and general guidelines from international entities such as IOGP, IPIECA, IADC and ARPEL.

Our HSE Policy

Our policy seeks to meet or exceed safety and environmental regulations in the countries in which we operate. We believe that oil and gas can be produced in an environmentally responsible manner with proper care, understanding and management, while safeguarding the well-being of all people. Within our SPEED philosophy we have a team that is exclusively focused on securing the environmental authorizations and permits for the projects we undertake and promoting the best health and safety practices. This professional and trained team, specialized in environmental issues, is also responsible for the achievement of the health, safety and environmental standards set by our board of directors and for training and supporting our personnel. Our senior executives, personnel in the field, visitors and contractors have also received training in proper health, safety and environmental management.

Our health and safety practices and outcomes

We continue to improve and update management tools to strengthen our health and safety policy. We have implemented world-class programs focused on analyzing, assessing and controlling hazards that may cause injury or illness to our employees, contractors and visitors.

In 2022, we reached several significant milestones, among which the following stand out:

- In the Llanos 34 Block, three drill rigs completed three years without lost-time incidents.
- Our assets in Putumayo (Colombia) and Ecuador, which maintained a constant operation throughout 2022, had no recordable people incidents.
- POP (Proactive Observation Program) cards increased by 27%.
- Application of SOS (Safety Operational Standards) checklists increased by 47%.

As of December 31, 2022, in the last twelve months, our HS indicators were the following:

- People injury. Indicators calculated per 1,000,000 hours worked (for both employees and contractors):
  - Lost time injury rate (LTIR) of 0.35 (39% lower than last five-year average).
  - Total recordable incident rate (TRIR) of 0.70 (54% lower than last five-year average).
  - Zero fatal incidents in the operation.
- Vehicle incidents, calculated per 1,000,000 kilometers travelled:
  - Rate of recordable vehicular incidents (MVC) of 0.17.

Additionally, in April 2022, we assumed the presidency of the Environment, Health and Industrial Safety Committee (CASYSIA) of ARPEL. The main achievements of the committee have been the publication of a checklist for the self-assessment of process safety management systems and the carrying out of an executive training program in safety.

Certain Bermuda law considerations

We have been designated by the Bermuda Monetary Authority as a non-resident for Bermuda exchange control purposes. This designation allows us to engage in transactions in currencies other than the Bermuda dollar, and there are no restrictions on our ability to transfer funds (other than funds denominated in Bermuda dollars) in and out of Bermuda or to pay dividends to United States residents who are holders of our common shares.

Insurance

We maintain insurance coverage of types and amounts that we believe to be customary and reasonable for companies of our size and with similar operations in the oil and gas industry. However, as is customary in the industry, we do not insure fully against all risks associated with our business, either because such insurance is not available or because premium costs are considered prohibitive.

Currently, our insurance program includes, among other things, construction, fire, vehicle, technical, umbrella liability, cyber security, director's and officer's liability and employer's liability coverage. Our insurance includes various limits and deductibles or retentions, which must be met prior to or in conjunction with recovery. A loss not fully covered by insurance could have a materially adverse effect on our business, financial condition and results of operations. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Oil and gas operations contain a high degree of risk, and we may not be fully insured against all risks we face in our business."

Industry and regulatory framework

Colombia

Regulation of the oil and gas industry

The ANH is responsible for managing all exploration acreage not subject to previously existing association contracts with Ecopetrol. Two decades ago, the ANH began offering all undeveloped and unlicensed exploration areas in the country under concession-fashion Exploration and Production Contracts ("E&P contracts") and Technical Evaluation Agreements, (or "TEAs"), which resulted in a significant increase in Colombian exploration activity and competition, according to the ANH. The regime for ANH's contracts is set forth in Agreement 008 of 2004 and Agreement 004 of 2012. Agreement 008 of 2004 issued by the Directive Council of the ANH, as replaced by Agreement 004 of 2012, sets forth the necessary steps for entering into a E&P contract with the ANH. This Agreement regulates E&P contracts entered into from May 4, 2012, and onwards. E&P contracts signed before that date are still regulated by Agreement 008 of 2004. Due to the oil price crisis of 2015, the ANH implemented transitory measures through Agreements 002, 003, 004 and 005 of 2015. On May 18, 2017, the ANH issued Agreement 002, which replaced Agreement 004 of 2012 and transitory measures adopted in 2014 and 2015. Agreement 002 of 2017 established rules for granting hydrocarbon areas and adopted criteria for the exploration and exploitation of hydrocarbons owned by Colombia, including the selection of contractors, and management, execution, termination, liquidation, monitoring, control, and supervision of corresponding contracts. Agreement 002 of 2017 (compiled by Acuerdo 009 of 2021) regulates contracts entered into from May 18, 2017, and onwards. E&P contracts entered into before that date are still regulated by the agreements under which they were executed. From 2004, the ANH has promoted several bidding processes resulting in various E&P contracts.

In 2020, and due to COVID-19 pandemic and the then-current oil low price scenario, the ANH issued Agreement 002 of 2020 with transitory relief measures such as term extensions for the exploratory phases, reduction of the amounts of the guarantees, among other measures. All these measures are subject to the accomplishment of certain conditions, some of which are related to the average oil price for the previous months. In 2021, ANH issued Agreement 010 of 2021 to enable the execution of pending investments in any free area on the map of available areas published by ANH. This agreement has enabled companies with E&P contracts with pending obligations (investments) to execute them in other areas promoting exploration activities in Colombia whilst helping companies comply with contractual commitments. In 2022, ANH issued Agreement 01, 2022 to regulate termination requests of E&P contracts under specific conditions such as being suspended for at least 24 consecutive months. This agreement enables companies to request termination of E&P contracts which appear to be inexecutable due to external factors out of a company's control.

In 2022, the government publicly announced its position regarding maintaining the existing E&P contracts but not granting areas for new contracts, hence no new bidding rounds are foreseen in the immediate future at the ANH.

Regulatory framework

Regulation of exploration and production activities

Pursuant to Colombian law, the state is the exclusive owner of all hydrocarbon resources located in Colombia and has full authority to determine the rights, royalties or compensation to be paid by private investors for the exploration or production of any hydrocarbon reserves. The Ministry of Mines and Energy is the authority responsible for creating national energy policy and regulating all activities related to the exploration and production of hydrocarbons in Colombia.

Decree Law 1056 of 1953 (*Código de Petróleos*), or the Petroleum Code, establishes the general procedures and requirements that must be completed by a private investor and disclosure procedures that should be met during the performance of these activities.

Exploration and production activities were governed by Decree 1895 of 1973 until September 2009. Decree Law 2310 of 1974 (as complemented by Decree 743 of 1975) governed the contracts and contracting processes carried out by Ecopetrol and the rules applicable to such contracts and provided that Ecopetrol was responsible for administering the hydrocarbons resources in the Country. Decree 2310 of 1974 was replaced by Decree Law 1760 of 2003, which restructured the hydrocarbons sector, but all agreements entered into by Ecopetrol prior to 2003 with other oil companies are still regulated by Decree 2310 of 1974. By Decree Law 1760 of 2003, Ecopetrol was spun off and the ANH was created. One of the main purposes of this decree was to treat Ecopetrol as another oil and gas company in the market and to transfer regulatory functions to the ANH as administrator of the nation's hydrocarbons. This enabled Ecopetrol to differentiate its role and avoid it being a party and judge to contractual matters.

Resolution 18-1495 of 2009, modified by Resolution 40048 of 2015, establishes a series of regulations regarding hydrocarbon exploration and exploitation. In the E&P contracts, operators are afforded access to blocks by committing to perform an exploratory work program. These E&P contracts provide companies with 100% of new production, less the participation of the ANH, which participation may differ for each E&P contract and depends on the percentage that each company has offered to the ANH in order to be granted with a block, applicable royalties and revenue taxes. In addition, the Colombian government also introduced TEAs, in which companies that enter into TEAs are the only ones to have the right to explore, evaluate and select desirable exploration areas by executing seismic and /or drilling stratigraphic wells and to propose work commitments on those areas, and have a preemptive right to enter into an E&P contract (Right to convert the TEA contract into an E&P contract), thereby providing companies with low-cost access to larger areas for preliminary evaluation prior to committing to broader exploration programs. Under a TEA, the contractor commits to exclusively perform the committed exploration activities.

Pursuant to Colombian law, oil companies are obliged to pay royalties (a percentage of their production) to the ANH in kind or in money as per ANH's instruction and pursuant to the E&P contracts. Companies must also pay the ANH an economic right called participating interest in the production, commonly known as "X factor" among other economic rights established in the E&P contracts (i.e. high price provision, technology transfer, use of the subsurface). Producing fields pay royalties in accordance with the applicable law at the time of the discovery. Under the E&P contracts, ANH contractors also undertake obligations in favor of the communities located in the area of influence of the oil & gas projects, called "*Proyectos en Beneficio de las Comunidades*" or (PBC).

In 2022, ANH launched Ronda Colombia 2021 with an addition to the terms of reference to include the Exclusivity Economic Value (EEV). The EEV includes both the minimum amount required by the ANH and the additional amount eventually included in the proposal, and which should be offered by the initial offers and counteroffers to surpass the initial proposal and equalize or exceed the most favorable counteroffer presented in each round. EEV is represented in the number of exploratory wells offered by a company to be drilled during the E&P contract's exploratory phase of six years. The companies should offer at least 1 EEV (minimum accepted by ANH) and grant a stand-by letter of credit for 100% of the estimated value of the well as per ANH's reference values. In the event the company does not comply with the offered EEV, the letter of credit will be enforced by ANH. ANH granted 30 areas in Ronda Colombia 2021 in which we did not participate.

Taxation

The Tax Statute and Law 9 of 1991 provide the primary features of the oil and gas industry's tax and foreign exchange system in Colombia. Generally, national taxes under the general tax statute apply to all taxpayers, regardless of industry.

The latest tax reform was enacted in December 2022, including modifications to the corporate income tax rate and the tax treatment of royalties, in-kind and in cash. See Note 16 to our Consolidated Financial Statements.

The main taxes currently in effect are the income tax (35%, plus a surtax for companies developing crude oil extractive activities from 2023 onwards, ranging between 0% and 15%, depending on the Brent oil price level), capital gains tax (15%), sales or value added tax (19%), and the tax on financial transactions (0.4%).

Additional regional taxes also apply with some special rules for the companies belonging to the oil and gas industry. Colombia has entered into a number of international tax treaties to avoid double taxation and prevent tax evasion in matters of income tax and net asset tax.

Decree 2080 of 2000 (amended by Decree 4800 of 2010), or the international investment regime, regulates foreign capital investment in Colombia. Resolution 1/2018 of the board of the Colombian Central Bank, or the Exchange Statute, and its amendments contain provisions governing exchange operations. Articles 94 to 97 of Resolution 1 provide for a special exchange regime for the oil industry that removes the obligation of repayment to the foreign exchange market currency from foreign currency sales made by foreign oil companies.

Such companies may not acquire foreign currency in the exchange market under any circumstances and must reinstate in the foreign exchange market the capital required in order to meet expenses in Colombian legal currency. Companies can avoid participating in this special oil and gas exchange regime, however, by informing the Colombian Central Bank and Ministry of Mines and Energy, in which case they will be subject to the general exchange regime of Resolution 1 and may not be able to access the special exchange regime for a period of 10 years.

Chile

Regulation of the oil and gas industry

Under the Chilean Constitution, the state is the exclusive owner of all mineral and fossil substances, including hydrocarbons, regardless of who owns the land on which the reserves are located. The exploration and exploitation of hydrocarbons may be carried out by the state, companies owned by the state or private entities through administrative concessions granted by the President of Chile by Supreme Decree or CEOPs executed by the Minister of Energy. Exploitation rights granted to private companies are subject to special taxes and/or royalty payments. The hydrocarbon exploration and exploitation industry is supervised by the Chilean Ministry of Energy.

In Chile, a participant is granted rights to explore and exploit certain assets under a CEOP. If a participant breaches certain obligations under a CEOP, the participant may lose the right to exploit certain areas or may be required to return all or a portion of the awarded areas to Chile with no right of compensation. Although the government of Chile cannot unilaterally modify the rights granted in the CEOP once it is signed, exploration and exploitation are nonetheless subject to significant government regulations, such as regulations concerning the environment, tort liability, health and safety and labor.

Regulatory framework

Regulation of exploration and production activities

Oil and gas exploration and development is governed by the Political Constitution of the Republic of Chile and Decree with Law Force No 2 of 1986 of the Ministry of Mines, which set forth the revised text of the Decree Law 1089 of 1975, on CEOPS. However, the right to explore and develop fields is granted for each area under a CEOP between Chile and the relevant contractors. The CEOP establishes the legal framework for hydrocarbon activities, including, among other things, minimum investment commitments, exploration and exploitation phase durations, compensation for the private company (either in cash or in kind) and the applicable tax regime. Accordingly, all the provisions governing the exploitation and development of our Chilean operations are contained in our CEOPs and the CEOPs constitute all the licenses that we need in order to own, operate, import and export any of the equipment used in our business and to conduct our gas and petroleum operations in Chile.

Under Chilean law, the surface landowners have no property rights over the minerals found under the surface of their land. Subsurface rights do not generate any surface rights, except the right to impose legal easements or rights of way. Easements or rights of way can be individually negotiated with individual surface landowners or can be granted without the consent of the landowner through judicial process. Pursuant to the Chilean Code of Mines, a judge can permit a party to use an easement pending final adjudication and settlement of compensation for the affected landowner.

Taxation

Under the Chilean tax regime, hydrocarbon exploitation benefits from the general income tax legislation are established at the time of the execution of each CEOP for the exploitation of each block. Thus, new tax reforms do not affect the current taxation for our subsidiaries in Chile.

Further, transactions between foreign related parties and our local subsidiaries are compliant with several tax reporting provisions set forth by the Chilean legislation for transfer pricing and indirect transfer tax purposes, at the same time that benefits derived from double taxation agreements entered into by Chile and the relevant countries are applied as well.

Brazil

Regulation of the oil and gas industry

Article 177 of the Brazilian Federal Constitution of 1988 provides for the Federal Government's monopoly over the prospecting and exploration of oil, natural gas resources and other fluid hydrocarbon deposits, as well as over the refining, importation, exportation and sea or pipeline transportation of crude oil and natural gas. Initially, paragraph one of article 177 barred the assignment or concession of any kind of involvement in the exploration of oil or natural gas deposits to private industry. On November 9, 1995, however, Constitutional Amendment Number 9 altered paragraph one of article 177 so as to allow private or state-owned companies to engage in the exploration and production of oil and natural gas, subject to the conditions to be set forth by legislation.

Regulatory framework

Pricing policy

Until the enactment of the Brazilian Petroleum Law, the Brazilian government regulated all aspects of the pricing of oil and oil products in Brazil, from the cost of oil imported for use in refineries to the price of refined oil products charged to the consumer. Under the rules adopted following the Brazilian Petroleum Law, the Brazilian government changed its price regulation policies. Under these regulations, the Brazilian government: (1) introduced a new methodology for determining the price of oil products designed to track prevailing international prices denominated in U.S. dollars, and (2) gradually eliminated controls on wholesale prices.

Concessions

In addition to opening the Brazilian oil and natural gas industry to private investment, the Brazilian Petroleum Law created new institutions, including the ANP, to regulate and control activities in the sector. As part of this mandate, the ANP is responsible for licensing concession rights for the exploration, development and production of oil and natural gas in Brazil's sedimentary basins through a transparent and competitive bidding process. The ANP has conducted 17 bidding rounds for exploration concessions from 1999 through 2021, three open acreage bid rounds (the third in course), 6th Production Sharing Bidding Round and two Transfer of Right Surplus Bidding Round.

Taxation

The Brazilian Petroleum Law introduced significant modifications and benefits to the taxation of oil and natural gas activities. The main component of petroleum taxation is the government take, comprised of license fees, fees payable in connection with the occupation or title of areas, royalties and a special participation fee. The introduction of the Brazilian Petroleum Law presents certain tax benefits primarily with respect to indirect taxes. Such indirect taxes are very complex and can add significantly to project costs. Direct taxes are mainly corporate income tax and social contribution on net profit.

With the effectiveness of the Brazilian Petroleum Law and the regulations promulgated by the ANP, concessionaires are required to pay the Brazilian federal government the following:

- license fees;
- rent for the occupation or retention of areas;
- special participation fee; and

- royalties on production.

The minimum value of the license fees is established in the bidding rules for the concessions, and the amount is based on the assessment of the potential, as conducted by the ANP. The license fees must be paid upon the execution of the concession contract. Additionally, concessionaires are required to pay a rental fee to landowners varying from 0.5% to 1.0% of the respective hydrocarbon production.

The special participation fee is an extraordinary charge that concessionaires must pay in the event of obtaining high production volumes and/or profitability from oil fields, according to criteria established by applicable regulation, and is payable on a quarterly basis for each field from the date on which extraordinary production occurs. This participation rate, whenever due, may reach up to 40% of net revenues depending on (i) volume of production and (ii) whether the block is onshore, shallow water or deep water. Under the Brazilian Petroleum Law and applicable regulations issued by the ANP, the special participation fee is calculated based upon quarterly net revenues of each field, which consist of gross revenues calculated using reference prices published by the ANP (reflecting international prices and the exchange rate for the period) less: royalties paid; investment in exploration; operational costs; and depreciation adjustments and applicable taxes.

The ANP is responsible for determining monthly minimum prices for petroleum produced in concessions for purposes of royalties payable with respect to production. Royalties generally correspond to a percentage ranging between 5% and 10% applied to reference prices for oil or natural gas, as established in the relevant bidding guidelines (*edital de licitação*) and concession agreement. In determining the percentage of royalties applicable to a particular concession, the ANP takes into consideration, among other factors, the geological risks involved, and the production levels expected.

State VAT (ICMS)

ICMS is a state sales tax. This tax is due on the local sale of oil and gas, based on the sale price, including the ICMS itself.

For intrastate transactions (carried out by a seller and a buyer located in the same Brazilian state) or imports, the ICMS rate is determined by the legislation of the state where the sale is made and generally varies from 17% to 20%. Interstate transactions (carried out between a seller and buyer located in different Brazilian states), in turn, are subject to reduced rates of 4% (if the products are imported and not submitted to a manufacturing process or, in case of further manufacturing, if the resulting product has a minimum imported content of 40%), 7% or 12%, depending on the states involved. One exception is that, due to the immunity established by the Brazilian Federal Constitution, ICMS is not due on interstate crude oil transactions when destined to industrialization and commercialization. On the other hand, in case of consumables or fixed assets, the buyer must pay to the state where the buyer is located, the ICMS DIFAL, which is calculated based on the difference between the interstate rate and the buyer's own internal ICMS rate.

ICMS is calculated under the noncumulative regime, and therefore some input transactions could result in tax credits (for example the acquisition of inputs and fixed assets directly used in the company's activity).

Social contribution taxes on gross revenue (PIS and COFINS)

PIS and COFINS are social contribution taxes charged on gross revenues earned by a Brazilian Federal Revenue noncumulative regime of calculation.

Under the noncumulative regime, PIS and COFINS are generally charged at a combined nominal rate of 9.25% (1.65% PIS and 7.6% COFINS) on national revenues earned by a legal entity. In that case, certain business costs result in tax credits to offset PIS and COFINS liabilities (e.g., input and services acquisitions, expenses of depreciation and amortization of machinery, equipment and other fixed assets acquired to be directly used in the company's activities). PIS and COFINS paid upon the importation of certain inputs, assets and services contracted that are destined to the company's activity are also creditable. Although upstream industries are generally subject to this regime, it is not clear yet when this benefit is applied according to the stage of the field, (exploration or production).

Since July 1, 2015, taxpayers subject to the noncumulative regime must calculate PIS and COFINS over certain financial revenues, applying rates of 0.65% and 4%, respectively.

Federal Industrialization VAT (IPI) and Municipality VAT (ISS)

IPI is a non-cumulative tax and may be due on goods acquisitions by importation or national transactions. The IPI rate will be applied depending on the NCM classification of the product according to TIPI (Table of IPI). On the acquisition of local goods subject to IPI, such tax is included in the price of the good. Considering that O&G activity (upstream) is not subject to IPI taxation, the amount of the tax cannot be considered as a credit (even though IPI is under the non-cumulative regime applicable for IPI's taxpayers), which means that this will be a cost for the legal entity acquirer. In relation to the importation, the importer of record will be considered as the taxpayer and will be obliged to pay the IPI due on the transaction. For the same aforementioned reasons for the O&G companies (upstream), this will be considered as cost when the importation is subject to IPI.

ISS is a cumulative tax which is due on provided services and imported services. Usually, regarding local transactions, such tax is included in the price of the service charged by the service provider. In relation to the import of service, the Brazilian entity contractor is responsible for the payment of the ISS, which means that, depending on contractual arrangement, the tax burden may be supported by the Brazilian contractor or the foreign service provider.

ISS tax rate may vary from 2% to 5% and will depend on the nature of service, as well as where the service provider is located (in general, some exceptions may apply).

Additionally, GeoPark Brazil was granted in 2018 a tax benefit issued by SUDENE (Northeastern Development Superintendence), by means of the Constitutive Act No. 0069/2018, which approved the tax incentive to reduce by 75% the Income Tax and Additions, calculated over the company exploration profits, based on Article 1 of the Provisory Measure 2,199-14 of August 24, 2001, in accordance with the requirements established by the Decree 6,539 of August 18, 2008.

The benefit will be valid for 10 years, starting from January 1, 2018, under the condition of modernizing the entire project on the SUDENE operating area, observing all provided legal conditions and requirements that includes compliance with labor and social law and with all environmental protection and control regulations, annual submission of a declaration of income and a restriction to the distribution to partners or shareholders of the tax amount which is not paid due to the tax exemption.

The noncompliance with the requirements provided constitutes a default of the beneficiary company in respect to SUDENE and shall be subject to the applicable penalties.

Argentina

Regulatory framework

The Hydrocarbon Law No. 17,319 enacted in 1967 continues in force until today, subject to amendments introduced by the Laws No. 24,145, 26,197 and 27,007. The Petroleum Deregulation Decrees (as defined below), with the limitations thereon introduced by the YPF expropriation law 26,741 (the "Hydrocarbons Sovereignty Act") and its regulations also molds the current national hydrocarbons regulatory framework.

The Hydrocarbon Law No. 17,319 provided for the existence of a state-owned oil & gas company (originally, YPF) for whom private companies served as service contractors or joint venture partners. But it also provided for a concession & royalty system which in practice was not used until after the YPF privatization.

In 1989, Argentina enacted certain laws aimed at privatizing the majority of its state-owned companies and issued a series of presidential decrees (namely, Decrees No. 1055/89, 1212/89 and 1589/89 (the "Petroleum Deregulation Decrees")), relating specifically to the deregulation of energy activities. In 1992, Law No. 24,145, referred to as the

Privatization Law, privatized YPF and provided for transfer of hydrocarbon reservoirs from the Argentine government to the provinces, subject to the existing rights of the holders of exploration permits and production concessions.

In October 2004, the Argentine Congress enacted Law No. 25,943, creating a new state-owned energy company, Energía Argentina S.A. ("ENARSA"). The corporate purpose of ENARSA was initially the exploration and exploitation of solid, liquid and gaseous hydrocarbons; the transport, storage, distribution, commercialization and industrialization of these products; as well as the transportation and distribution of natural gas, and the generation, transportation, distribution and sale of electricity.

On May 3, 2012, the Argentine Congress passed the Hydrocarbons Sovereignty Act. This law declared achieving self-sufficiency in the supply of hydrocarbons, as well as in the exploitation, industrialization, transportation and sale of hydrocarbons, a national public interest and a priority for Argentina. In addition, the law expropriated 51% of the share capital of YPF, the largest Argentine oil company, from Repsol, the largest Spanish oil company.

Regarding the export regime, Argentina passed on September 3, 2018, Decree 793/2018, which established a 12% export duty on all exports of goods from Argentina until December 31, 2020, including hydrocarbons exports. Then, the Economic Emergency Law 27,541 enacted on December 21, 2019, reduced to 8% the maximum export duty authorized to be levied on hydrocarbon exports as provided under Decree 793/2018. Lastly, National Decree 488/2020 passed in May 2020, in response to the COVID-19 pandemic, abrogated oil export duties as long as the Brent benchmark quotes at US$45 or under and reduced the export duties to 8% for when the Brent benchmark quotes at US$60 or over. A prorated export duty formula was established for periods when the Brent benchmark quotes between US$45 and US$60.

Domain and Jurisdiction of hydrocarbons resources

After a constitutional reform enacted in 1994, eminent domain over hydrocarbon resources lying in the territory of a provincial state is now vested in such provincial state, while eminent domain over hydrocarbon resources lying offshore on the continental platform beyond the jurisdiction of the coastal provincial states is vested in the federal state.

Thus, oil and gas exploration permits and exploitation concessions are now granted by each provincial government. A majority of the existing concessions were granted by the federal government prior to the enactment of Law No. 26,197 and were thereafter transferred to the provincial states.

Hydrocarbon Exports and Self-Sufficiency

Achieving self-sufficiency has been an energy policy goal from the early days of the industry.

Section 6 of the Hydrocarbon Law No. 17,319 allows the National Executive Branch to authorize the export of hydrocarbons. At times when the domestic production of liquid hydrocarbons is insufficient to cover domestic needs, the delivery of the entire availability of such locally produced hydrocarbons to the domestic market shall be mandatory, with such exceptions as may be justified on technical grounds.

In turn, Section 3 of the Natural Gas Regulatory Framework 24,076 allows the National Executive Branch to authorize the export of natural gas. The granting of natural gas export permits is regulated in detail.

Supply privileges favoring the domestic market to the detriment of the export market, including hydrocarbon export restrictions, domestic price controls, price subsidies, export duties and domestic market supply obligations have been implemented several times.

In November 2020, National Decree 892/2020 approved a Plan for the Promotion of the Production of Argentine Natural Gas – Supply and Demand Scheme 2020-2024 whereby the National Government agreed to compensate natural gas producers for the share of the price of natural gas they auctioned that is not transferred to end-users according to the passthrough mechanism provided in their license terms. Three subsequent Rounds of natural gas supply auctions have been conducted since then by the National Secretary of Energy under which participating producers committed to inject natural gas volumes required to satisfy the demand of domestic market utilities in consideration for government monetary compensation and certain natural gas export allowances.

Regulation of exploration and production activities

New Hydrocarbon Act:

In October 31, 2014, the Argentine Republic Official Gazette published the text of Law No. 27,007, amending the Hydrocarbon Law No. 17,319.

The most relevant aspects of the new law are as follows:

- With regards to concessions, three types of concessions are provided, namely, conventional exploitation, unconventional exploitation, and exploitation in the continental shelf and territorial waters, establishing the respective terms for each type.

- The terms for hydrocarbon transportation concessions were adjusted in order to comply with the exploitation concessions terms.

- With regards to royalties, a maximum of 12% was established, which may reach 18% in the case of granted extensions, where the law also establishes the payment of an extension bond for a maximum amount equal to the amount resulting from multiplying the remaining proven reserves at the end of effective term of the concession by 2% of the average basin price applicable to the respective hydrocarbons over the 2 years preceding the time on which the extension was granted.

- The Investment Promotion Regime for the Exploitation of Hydrocarbons (Decree No. 929/2013) was extended to projects representing a direct investment in foreign currency of at least 250 million dollars and, additional benefits were included.

Regulation of transportation activities

Exploitation concessionaires have the exclusive right to obtain a transportation concession for the transport of oil and gas from the provincial states or the federal government, depending on the applicable jurisdiction. Such transportation concessions include storage, ports, pipelines and other fixed facilities necessary for the transportation of oil, gas and by-products. Transportation facilities with surplus capacity must transport third parties' hydrocarbons on an open-access basis, for a fee which is the same for all users on similar terms. As a result of the privatizations of YPF and Gas del Estado, a few common carriers of crude oil and natural gas were chartered and continue to operate to date.

Effective February 8, 2019, to promote transportation capacity expansions, Decree 115/2019 allowed interested shippers to reserve transportation capacity in new or expanded pipelines through freely negotiated capacity reservation agreements.

Taxation

Exploitation concessionaires are subject to the general federal and provincial tax regime. The most relevant federal taxes are the income tax (35%) and the value-added tax (21%). The most relevant provincial taxes are the turnover tax (3% on average) and stamp tax. Corporate income tax rate may range from 25% to 35% on bands of income that can be adjusted annually.

Ecuador

Regulatory framework

Petroleum Ownership and Regulation

Oil, gas, minerals and natural resources underground belong to the Republic of Ecuador, in accordance with the Ecuadorian Constitution. This is a primary concept in both the Constitution and the law. However, the State can allow private investment to explore and produce hydrocarbons under different types of contracts as provided under the law.

The Ministry of Energy and Non-Renewable Natural Resources regulates and oversees all hydrocarbon-related activities in the country, including exploration, production, transportation, refining and marketing. The Ministry has absorbed the functions and duties of the Secretariat of Hydrocarbons and, through the Vice-Ministry of Hydrocarbons, oversees awarding, executing and monitoring contracts with private companies for the exploration and production of hydrocarbons. On the other hand, the Agency for Regulation and Control of Energy and Non-Renewable Natural Resources ("ARCERNNR" for its Spanish acronym) has the legal duty to oversee, audit, collect levies and duties on operations, and conduct accounting control of all upstream and downstream hydrocarbon operations.

The Ministry of the Environment, Water and Ecological Transition of Ecuador ("MAATE" for its Spanish acronym) has the legal competence for granting environmental licenses for all oil and gas activities and to ensure such operations are conducted in compliance with environmental laws and regulations. The Ministry of the Environment is independent from the Ministry of Energy.

Petroleum Laws and Regulations

The Ecuadorian Constitution contains the main provisions, which stipulate that all hydrocarbons belong to the State of Ecuador, that the national oil company is EP PETROECUADOR has preferential rights for oil exploration, production, transportation and sale, and that, in case a contract is executed with a private oil company, the State's benefit must be more than that of the private company. The State's benefit is understood as all taxes, production sharing and other economic benefits the State receives from oil production, while the company's benefit is understood as all proceeds received from payment for the service of producing oil, or from the sales of its share of oil, less all amortization of investments, costs and taxes paid by the company.

The Hydrocarbons Law is the main body of law below the Ecuadorian Constitution and regulates the different types of contracts the government can enter into with international oil companies, as well as the rights, obligations and penalties for private companies. The main contracts that have been implemented in Ecuador from time to time are service contracts and fairly recently the production-sharing contracts ("PSC"). Under a service contract, the State of Ecuador pays a contractually agreed tariff per barrel. Under a PSC, the investing company receives a share of the oil produced which it can freely trade.

There are several regulations ranking below the Hydrocarbons Law that set further rules for all activities, including the regulation of hydrocarbon operations and special local rules on the accounting principles for each type of contract.

In addition to all the other generally applicable laws of the country, the Environmental Law, Labor Law (including local content in hiring of personnel) and Tax Law should be carefully considered.

Background for Contract types for Private Investment in Petroleum

During almost 50 years Ecuador has been producing oil, through two types of contracts: production-sharing contracts and service contracts. The government has imposed service contracts when the price of oil was high and production-sharing contracts when the price of oil was low. In 2010, a legal reform required all oil companies that were operating under the umbrella of production-sharing contracts to transform their contracts into service contracts.

Service contracts can be executed by the Ministry of Hydrocarbons for exploration blocks or for fields already in production (followed a 2021 reform to the Law of Hydrocarbons). In both cases, the contracting company receives a pre-agreed tariff that is usually negotiated considering the amount of the investment, existing reserves, production cost and an estimated reasonable profit for the company.

In July 2018, Executive Decree no. 449 reinstated the production-sharing type of contracts so called locally as Participation Contracts. On 2019, the Ministry of Energy executed several Participation Contracts for exploration and exploitation of hydrocarbons.

The contract term for a production-sharing contract is usually four years for exploration, extendable for two additional years, and 20 years for production, subject to an extension if reserves have been added and new investments are committed. As of the date of this annual report, we hold two production-sharing contracts with a 50% working interest in consortium with Frontera Energy (Espejo Block, operated, and non-operated Perico Block), which were awarded by the Ministry of Energy during the First Intracampos Bidding Round in April 2019.

After a reform to the Law of Hydrocarbons enacted in 2021, oil companies can transform a service contract into a production sharing contract through a request to the Ministry of Energy and negotiating certain new terms and conditions applicable to the production-sharing contract.

Taxation

The guiding principle is that the government's share will always be higher than the contracting company's share. If the contracting company's share is higher than 51%, it triggers a sovereignty margin adjustment in favor of the government.

In a risk service contract, the government's share comprises the oil sales price or the reference price for a specific month, less the tariff paid to the company and plus all applicable taxes. For this type of contract, the contracting company's share is composed of the tariff received from the government per barrel, less the amortization of investments, operating costs and all applicable taxes and contributions paid in accordance with the law and the contract.

Under a production-sharing contract, the government's share is composed of the sales price or the reference price of the share of oil assigned to the government as per the contract, plus all taxes and contributions paid by the company. In this type of contract, the contracting company's share is the higher of the sales price and the reference price of the company's oil, less all amortization of investments, operating costs, transportation costs up to the port of Balao on the Pacific Coast and all taxes and contributions paid pursuant to the law and the contract.

Basically, the taxes are:

- employee profit-sharing (15 per cent of net profits before income tax);
- 25 per cent income tax rate;
- 12 per cent value-added tax;
- 4 per cent money outflow tax, applied to offshore remittances, except when for profit distribution;
- municipal taxes; and
- other fees and contributions charged by petroleum oversight authorities.

Production Risk

For any type of contract to be entered into in Ecuador, the investing company has to take on all exploration and production risks and investments, as well as environmental responsibilities in accordance with its corresponding environmental obligations.

Furthermore, the investing company must strictly abide by all employment laws, in terms of legal requirements concerning the maximum number of foreign employees. Some contracts have allowed for arbitration as a dispute resolution mechanism; however, certain matters, such as taxes, cannot be submitted to arbitration. This is also true for certain termination provisions in the event of the investing company breaching the law (such as transfer of rights without consent). The reform to the Law of Hydrocarbons enacted in 2021 allows the entry into investment treaties with the Government of Ecuador, allowing to freeze tax incentives in consideration for investment commitments and expanding local employment.

C. Organizational structure

We are an exempted company incorporated pursuant to the laws of Bermuda. We operate and own our assets directly and indirectly through a number of subsidiaries. See an illustration of our corporate structure in Note 21 ("Subsidiary undertakings") to our Consolidated Financial Statements.

D. Property, plant and equipment

See "—B. Business Overview—Title to properties."

ITEM 4A. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

A. Operating results

The following discussion of our financial condition and results of operations should be read in conjunction with our Consolidated Financial Statements and the notes thereto.

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including those set forth in "Item 3. Key Information—D. Risk factors" and "Forward-looking statements."

Factors affecting our results of operations

We describe below the year-to-year comparisons of our historical results and the analysis of our financial condition. Our future results could differ materially from our historical results due to a variety of factors, including the following:

Discovery and exploitation of reserves

Our results of operations depend on our level of success in finding, acquiring (including through bidding rounds) or gaining access to oil and natural gas reserves. While we have geological reports evaluating certain proved, contingent and prospective resources in our blocks, there is no assurance that we will continue to be successful in the exploration, appraisal, development and commercial production of oil and natural gas. The calculation of our geological and petrophysical estimates is complex and imprecise, and it is possible that our future exploration will not result in additional discoveries, and, even if we are able to successfully make such discoveries, there is no certainty that the discoveries will be commercially viable to produce.

For the year ended December 31, 2022, we made total capital expenditures of US$168.8 million (US$139.2 million, US$11.1 million and US$18.5 million in Colombia, Chile and Ecuador, respectively), consisting of US$67.9 million related to exploration.

Oil prices have been volatile, particularly since the start of the COVID-19 pandemic and the armed conflict in Ukraine. In preparation for continued volatility, we have developed multiple scenarios for our 2023 capital expenditure program. See "Item 4. Information on the Company—B. Business Overview—2023 Strategy and Outlook."

Funding for our capital expenditures relies in part on oil prices remaining close to our estimates or higher levels and other factors to generate sufficient cash flow. Low oil prices affect our revenues, which in turn affect our debt capacity and the covenants in our financing agreements, as well as the amount of cash we can borrow using our oil reserves as collateral, the amount of cash we are able to generate from current operations and the amount of cash we can obtain from prepayment agreements. If we are not able to generate the sales which, together with our current cash resources, are sufficient to fund our capital program, we will not be able to efficiently execute our work program which would cause us to further decrease our work program, which could harm our business outlook, investor confidence and our share price.

If oil prices average higher than the base budget price, we have the ability to allocate additional capital to more projects and increase our work and investment program and thereby further increase oil and gas production.

Our results of operations will be adversely affected in the event that our estimated oil and natural gas asset base does not result in additional reserves that may eventually be commercially developed. In addition, there can be no assurance that we will acquire new exploration blocks or gain access to exploration blocks that contain reserves. Unless we succeed in exploration and development activities, or acquire properties that contain new reserves, our anticipated reserves will continually decrease, which would have a material adverse effect on our business, results of operations and financial condition.

Oil and gas revenue and international prices

Our revenues are derived from the sale of our oil and natural gas production, as well as of condensate derived from the production of natural gas. The price realized for the oil we produce is generally linked to Brent. The price realized for the natural gas we produce in Chile is linked to the international price of methanol, which is settled in the international markets in US$. The market price of these commodities is subject to significant fluctuation and has historically fluctuated widely in response to relatively minor changes in the global supply and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors.

For example, during the three-year period from March 1, 2020, to February 28, 2023, Brent spot prices ranged from a low of US$19.3 per barrel to a high of US$128.0 per barrel.

We manage part of our exposure to the volatile crude oil price using derivatives. For further information related to Commodity Risk Management Contracts, please see Note 8 to our Consolidated Financial Statements.

Additionally, the oil and gas we sell may be subject to certain discounts. For example, in Colombia, the realized oil price is linked to either the Vasconia crude reference price, a marker broadly used in the Llanos Basin, or the Oriente crude reference price, a marker broadly used for crude sales in Esmeraldas, Ecuador, for the crude oil of the Putumayo Basin that is transported through Ecuador. In both basins, the reference price is then adjusted for certain marketing and quality discounts based on, among other things, API, viscosity, sulphur content, delivery point and transport costs.

In Chile, the price of oil we sell to ENAP is based on Dated Brent minus certain marketing and quality discounts such as, API, sulphur content and others. We have a long-term gas supply contract with Methanex. The price of the gas sold under this contract is determined by a formula that considers a basket of international methanol prices, including US and European price indices. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—A substantial or extended decline in oil, natural gas and methanol prices may materially adversely affect our business, financial condition or results of operations."

In Brazil, prices for gas produced in the Manati Field are based on a long-term off-take contract with Petrobras. The price of gas sold under this contract is denominated in *reais* and is adjusted annually for inflation pursuant to the Brazilian General Market Price Index (*Índice Geral de Preços—Mercado*) (the "IGPM").

In Ecuador, the oil price is linked to Brent and adjusted by a differential that varies month to month and resembles the Oriente crude reference price.

If oil and methanol prices had fallen by 10% compared to actual prices during the year, with all other variables held constant, considering the impact of the derivative contracts in place, post-tax profit for the year would have been lower by US$47.3 million (US$17.9 million in 2021).

Production and operating costs

Our production and operating costs consist primarily of expenses associated with the production of oil and gas, the most significant of which are facilities and wells maintenance (including pulling works), labor costs, contractor and consultant fees, chemical analysis, royalties, economic rights, and consumables, among others. As commodity prices increase or decrease, our production costs may vary. We have historically not hedged our costs to protect against fluctuations.

Availability and reliability of infrastructure

Our business depends on the availability and reliability of operating and transportation infrastructure in the areas in which we operate. Prices and availability for equipment and infrastructure, and the maintenance thereof, affect our ability to make the investments necessary to operate our business, and thus our results of operations and financial condition. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Our inability to access needed equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets and generate significant incremental costs or delays in our oil and natural gas production."

Production levels

Our oil and gas production levels are heavily influenced by our drilling results, our acquisitions and oil and natural gas prices.

We expect that fluctuations in our financial condition and results of operations will be driven by the rate at which production volumes from our wells decline. As initial reservoir pressures are depleted, oil and gas production from a given well will decline over time. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Unless we replace our oil and natural gas reserves, our reserves and production will decline over time. Our business is dependent on our continued successful identification of productive fields and prospects and the identified locations in which we drill in the future may not yield oil or natural gas in commercial quantities."

Contractual obligations

In order to protect our exploration and production rights in our licensed areas, we must make and declare discoveries within certain time periods specified in our various special contracts, E&P contracts and concession agreements. The costs to maintain or operate our licensed areas may fluctuate or increase significantly, and we may not be able to meet our commitments under these agreements on commercially reasonable terms or at all, which may force us to forfeit our interests in such areas. If we do not succeed in renewing these agreements, or in securing new ones, our ability to grow our business may be materially impaired. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Under the terms of some of our various CEOPs, E&P contracts, production sharing agreements and concession agreements, we are obligated to drill wells, declare any discoveries and file periodic reports in order to retain our rights and establish development areas. Failure to meet these obligations may result in the loss of our interests in the undeveloped parts of our blocks or concession areas."

Acquisitions

As described above, part of our strategy is to acquire and consolidate assets in Latin America. We intend to continue to selectively acquire companies, producing properties and concessions. As with our historical acquisitions, any future acquisitions could make year-to-year comparisons of our results of operations difficult. We may also incur additional debt, issue equity securities or use other funding sources to fund future acquisitions. We generally incorporate our acquired business into our results of operations at or around the date of closing.

On January 16, 2020, we acquired the 100% share capital of Amerisur. Considering that Amerisur issues financial information monthly, we have considered the identified assets and liabilities as of December 31, 2019. If the purchase price allocation exercise had been carried out as of January 16, 2020, it would not have deferred significantly.

Functional and presentational currency

Our Consolidated Financial Statements are presented in US$, which is our presentation currency. Items included in the financial information of each of our entities are measured using the currency of the primary economic environment in which the entity operates, or the functional currency, which is the US$ in each case, except for our Brazil operations, where the functional currency is the *real*.

Geographical segment reporting

In the description of our results of operations that follow, our "Other" operations reflect our non-Colombian, non-Chilean, non-Argentine, non-Brazilian and non-Ecuadorean operations, primarily consisting of our corporate head office operations.

As of December 31, 2022, we divided our business into five geographical segments—Colombia, Chile, Brazil, Argentina, and Ecuador—that corresponded to our principal jurisdictions of operation. Activities not falling into these five geographical segments are reported under a separate corporate segment that primarily includes certain corporate administrative costs not attributable to another segment.

Description of principal line items

The following is a brief description of the principal line items of our consolidated statement of income.

Revenue

Revenue includes the sale of crude oil, condensate and natural gas net of value-added tax ("VAT"), and discounts related to the sale (such as API and mercury adjustments) and overriding royalties due to the ex-owners of oil and gas properties where the royalty arrangements represent a retained working interest in the property. Revenue from the sale of crude oil and gas is recognized when control of the product is transferred to the customer, which is generally when the product is physically transferred into a pipe or other delivery mechanism and the customer accepts the product. Consequently, the Group's performance obligations are considered to relate only to the sale of crude oil and gas, with each barrel of crude oil equivalent considered to be a separate performance obligation under the contractual arrangements in place.

Commodity risk management contracts

Includes realized and unrealized gains and losses arising from commodity risk management contracts.

The derivatives that hedge cash flows from the sales of crude oil for periods through December 31, 2022, are accounted for as non-hedge derivatives and therefore all changes in the fair values of these derivative contracts are recognized immediately as gains or losses in the results of the periods in which they occur.

The derivatives that hedge cash flows from the sales of crude oil for periods from January 1, 2023, and onwards are designated and qualify as cash flow hedges. The effective portion of changes in the fair values of these derivative contracts are recognized in Other Reserves within Equity. The gain or loss relating to the ineffective portion, if any, is recognized immediately as gains or losses in the results of the periods in which they occur. The amount accumulated in Other Reserves is reclassified to profit or loss as a reclassification adjustment in the same period or periods during which the hedged cash flows affect profit or loss.

Production and operating costs

Production and operating costs are recognized on the accrual basis of accounting. These costs include wages and salaries incurred to achieve the revenue for the year. Direct and indirect costs of raw materials and consumables, rentals, royalties and economic rights are also included within this account. For a description of our production and operating costs, see "—Factors affecting our results of operations."

Depreciation

Capitalized costs of proved oil and natural gas properties are depreciated on a licensed-area-by-licensed-area basis, using the unit of production method, based on commercial proved and probable reserves as calculated under the Petroleum Resources Management System methodology promulgated by the Society of Petroleum Engineers and the World Petroleum Council (the "PRMS"), which differs from SEC reporting guidelines pursuant to which certain information in the forepart of this annual report is presented. The calculation of the "unit of production" depreciation takes into account estimated future discovery and development costs. Changes in reserves and cost estimates are recognized prospectively. Reserves are converted to equivalent units on the basis of approximate relative energy content.

Geological and geophysical expenses

Geological and geophysical expenses are recognized on the accrual basis of accounting and consist of geosciences costs, including wages and salaries and share-based compensation not subject to capitalization, geological consultancy costs and costs relating to independent reservoir engineer studies.

Administrative expenses

Administrative expenses are recognized on the accrual basis of accounting and consist of corporate costs such as director fees and travel expenses, new project evaluations and back-office expenses principally comprised of wages and salaries, share-based compensation, consultant fees and other administrative costs, including certain costs relating to acquisitions.

Our administrative expenses for the year ended December 31, 2022, increased by US$3.2 million, or 7%, compared to the year ended December 31, 2021, mainly due to the increase in travel expenses and other costs related to projects that had been postponed due to the COVID-19 pandemic and the accrual of share-based programs granted during 2022.

Selling expenses

Selling expenses are recognized on the accrual basis of accounting and consist primarily of transportation, storage costs and selling taxes.

Our selling expenses for the year ended December 31, 2022, decreased by US$0.7 million, or 8%, compared to the year ended December 31, 2021, mainly due to (1) differences in accounting for different points of sale in Colombia, (2) the divestment of the Aguada Baguales, Puesto Touquet and El Porvenir Blocks on January 31, 2022, and (3) the first oil sales in Ecuador due to the successful drilling campaign in the Perico Block during the year.

Write-off of unsuccessful exploration efforts

Upon completion of the evaluation phase, the exploratory prospects are either transferred to oil and gas properties or charged to expense in the period in which the determination is made, depending on whether they have discovered reserves or not. If not developed, exploration and evaluation assets are written off after three years, unless it can be clearly demonstrated that the carrying value of the investment is recoverable.

During 2022, we recognized write-off of unsuccessful exploration efforts of US$25.8 million (US$12.3 million in 2021). See Note 20 to our Consolidated Financial Statements.

Impairment of non-financial assets

Assets that are not subject to depreciation and/or amortization are tested annually for impairment. Assets that are subject to depreciation and/or amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

An impairment loss is recognized for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value minus costs to sell and value in use.

During 2022, no impairment losses were recognized or reversed. We recognized a net impairment loss of US$4.3 million in 2021 that corresponded to: (1) an impairment loss recognized in the Fell Block of US$17.6 million due to the decline in the proved reserves estimation in 2021 and, (2) a reversal of impairment loss of US$13.3 million in the Aguada Baguales and El Porvenir Blocks in Argentina. See Note 37 to our Consolidated Financial Statements.

Financial results

Financial results include interest expenses, interest income, bank charges, the amortization of financial assets and liabilities, and foreign exchange gains and losses.

Recent accounting pronouncements

See Note 2.1.1 to our Consolidated Financial Statements.

Results of operations

The following discussion is of certain financial and operating data for the periods indicated. You should read this discussion in conjunction with our Consolidated Financial Statements and the accompanying notes.

In preparation for continued volatility, we have developed multiple scenarios for our 2023 capital expenditure program. See "Item 4. Information on the Company –B. Business Overview—2023 Strategy and Outlook."

Year ended December 31, 2022, compared to year ended December 31, 2021

The following table summarizes certain of our financial and operating data for the years ended December 31, 2022 and 2021.

	For the year ended December 31,		
	2022	**2021**	**% Change from prior year**
	(in thousands of US$, except for percentages)		
Revenue			
Sale of crude oil	1,004,775	647,559	55 %
Sale of purchased crude oil	9,454	—	100 %
Sale of gas	35,350	40,984	(14)%
Revenue	**1,049,579**	**688,543**	**52 %**
Commodity risk management contracts	(70,221)	(109,191)	(36)%
Production and operating costs	(359,779)	(212,790)	69 %
Geological and geophysical expenses	(10,529)	(7,891)	33 %
Administrative expenses	(50,024)	(46,828)	7 %
Selling expenses	(7,995)	(8,730)	(8)%
Depreciation	(96,692)	(88,969)	9 %
Write-off of unsuccessful exploration efforts	(25,789)	(12,262)	110 %
Impairment loss recognized for non-financial assets	—	(4,334)	(100)%
Other income (expenses)	527	(11,739)	(104)%
Operating profit	**429,077**	**185,809**	**131 %**
Financial expenses	(57,073)	(64,112)	(11)%
Financial income	3,180	1,652	92 %
Foreign exchange profit	19,725	5,049	291 %
Profit before income tax	**394,909**	**128,398**	**208 %**
Income tax expense	(170,474)	(67,271)	153 %
Profit for the year	**224,435**	**61,127**	**267 %**
Net production volumes			
Oil (mbbl)(2)	12,786	11,853	8 %
Gas (mcf)(3)	7,864	11,230	(30)%
Total net production (mboe)	14,096	13,725	3 %
Average net production (boepd)	38,620	37,602	3 %
Average realized sales price			
Oil (US$ per bbl)	82.2	58.3	41 %
Gas (US$ per mmcf)	4.8	4.0	21 %
Average unit costs per boe (US$)			
Operating cost	8.0	7.6	6 %
Royalties and economic rights	18.8	8.6	118 %
Production costs(1)	26.8	16.1	66 %
Geological and geophysical expenses	0.8	0.6	31 %
Administrative expenses	3.7	3.5	6 %
Selling expenses	0.6	0.7	(15)%

(1) Calculated pursuant to FASB ASC 932.

(2) We present production figures before deduction of royalties, as we believe that net production before royalties is more appropriate in light of our foreign operations and the attendant royalty regimes. Oil production figures presented on page F-73 are net of royalties.

(3) Corresponds to production measured after separation but prior to compression, which is the measure we used to monitor business performance. Gas production presented on page F-74 is gas measured at the point of delivery.

The following table summarizes certain financial data.

	For the year ended December 31,													
	2022							2021						
	Colombia	Chile	Brazil	Argentina	Ecuador	Other	Total	Colombia	Chile	Brazil	Argentina	Ecuador	Other	Total
	(in thousands of US$)													
Revenue	978,423	29,196	19,873	1,962	10,671	9,454	1,049,579	618,268	21,471	20,109	28,695	—	—	688,543
Depreciation	(78,775)	(14,076)	(2,796)	(254)	(788)	(3)	(96,692)	(61,279)	(14,275)	(4,082)	(9,130)	(200)	(3)	(88,969)
Impairment and write-off	(21,318)	—	—	—	(4,471)	—	(25,789)	(7,827)	(22,076)	—	13,307	—	—	(16,596)

Revenue

For the year ended December 31, 2022, crude oil sales were our principal source of revenue, with 96%, 1% and 3% of our total revenue from crude oil, purchased crude oil and gas sales, respectively. The following chart shows the change in oil and natural gas sales from the year ended December 31, 2021, to the year ended December 31, 2022.

	For the year ended December 31,	
	2022	2021
	(in thousands of US$)	
Consolidated		
Sale of crude oil	1,004,775	647,559
Sale of purchased crude oil	9,454	—
Sale of gas	35,350	40,984
Total	**1,049,579**	**688,543**

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
By country				
Colombia	978,423	618,268	360,155	58 %
Chile	29,196	21,471	7,725	36 %
Brazil	19,873	20,109	(236)	(1)%
Argentina	1,962	28,695	(26,733)	(93)%
Ecuador	10,671	—	10,671	100 %
Other	9,454	—	9,454	100 %
Total	**1,049,579**	**688,543**	**361,036**	**52 %**

Revenue increased 52%, from US$688.5 million for the year ended December 31, 2021, to US$1,049.6 million for the year ended December 31, 2022, primarily as a result of higher realized prices. Sales of crude oil increased due to higher realized prices and higher sold volumes of 12.2 mmbbl in the year ended December 31, 2022, compared to 11.5 mmbbl in the year ended December 31, 2021, and resulted in net revenue of US$1,004.8 million for the year ended December 31, 2022, compared to US$647.6 million for the year ended December 31, 2021. In addition, sales of gas decreased from US$41.0 million for the year ended December 31, 2021, to US$35.4 million for the year ended December 31, 2022, due to lower natural gas deliveries partially offset by higher realized prices.

The increase in 2022 net revenue of US$361.0 million is mainly explained by:

- an increase of US$360.2 million in sales in Colombia mainly due to higher realized prices plus higher deliveries;
- an increase of US$7.7 million in sales in Chile, due to higher realized prices partially offset by lower gas deliveries;
- the first oil sales in Ecuador of US$10.7 million due to the successful drilling campaign in the Perico Block during the year; and

- the trading operation performed by the holding company, GeoPark Limited, of US$9.5 million;

partially offset by:

- a decrease of US$0.2 million in sales in Brazil, mainly due to decreased gas deliveries partially offset by higher realized oil and gas prices; and

- a decrease of US$26.7 million in sales in Argentina due to the divestment of the Aguada Baguales, Puesto Touquet and El Porvenir Blocks on January 31, 2022.

Revenue attributable to our operations in Colombia for the year ended December 31, 2022, was US$978.4 million, compared to US$618.3 million for the year ended December 31, 2021, representing 93.2% and 89.8% of our total consolidated sales, respectively. The increase is related to an increase in the average realized price per barrel of crude oil from US$56.3 per barrel to US$82.7 per barrel, primarily due to higher reference international prices, plus an increase in oil deliveries from 10.9 mmbbl to 11.8 mmbbl.

Revenue attributable to our operations in Chile for the year ended December 31, 2022, was US$29.2 million, a 36% increase from US$21.5 million for the year ended December 31, 2021, principally due to (1) an increase in oil sales by US$8.2 million reflecting higher average realized prices per barrel of crude oil from US$62.8 per barrel for the year ended December 31, 2021, to US$94.7 per barrel for the year ended December 31, 2022 (an increase of US$31.9 per barrel or a total of 51%), plus an increase in oil deliveries from 0.10 mmbbl to 0.15 mmbbl, and, (2) a decrease in gas sales by US$0.4 million reflecting lower deliveries, partially offset by higher average realized prices from US$20.7 per boe for the year ended December 31, 2021, to US$22.7 per boe for the year ended December 31, 2022. The contribution to our revenue during the years ended December 31, 2022, and 2021, from our operations in Chile was 2.8% and 3.1%, respectively.

Revenue attributable to our operations in Brazil for the year ended December 31, 2022, was US$19.9 million, a 1% decrease from US$20.1 million for the year ended December 31, 2021, principally due to lower gas deliveries from 0.6 mmboe to 0.5 mmboe to respond to the lower gas demand in Brazil partially offset by higher realized gas prices from US$30.7 per boe for the year ended December 31, 2021, to US$38.3 per boe for the year ended December 31, 2022. The contribution to our revenue from our operations in Brazil during the years ended December 31, 2022 and 2021, was 1.9% and 2.9%, respectively.

Revenue attributable to our operations in Argentina for the year ended December 31, 2022, was US$2.0 million, compared to US$24.6 million for the year ended December 31, 2021, due to the divestment of the Aguada Baguales, Puesto Touquet and El Porvenir Blocks on January 31, 2022. The contribution to our revenue from our operations in Argentina during the years ended December 31, 2022 and 2021, was 0.2% and 4.2%, respectively.

Revenue attributable to our operations in Ecuador for the year ended December 31, 2022, was US$10.7 million, compared to zero for the year ended December 31, 2021, due to the successful drilling campaign in the Perico Block during the year. The contribution to our revenue from our operations in Ecuador during the year ended December 31, 2022, was 1.0%.

Revenue attributable to our trading operation performed by the holding company, GeoPark Limited, for the year ended December 31, 2022, was US$9.5 million, compared to zero for the year ended December 31, 2021. The contribution to our revenue from our trading operation during the year ended December 31, 2022 was 0.9%.

Production and operating costs

The following table summarizes our production and operating costs for the years ended December 31, 2022 and 2021.

	For the year ended December 31,		
	2022	2021	% Change from prior year
	(in thousands of US$, except for percentages)		
Consolidated (including Colombia, Chile, Brazil, Argentina, Ecuador and Other)			
Royalties	(63,298)	(40,000)	58 %
Economic rights	(188,989)	(73,023)	159 %
Staff costs and share-based payments	(14,069)	(16,994)	(17)%
Well and facilities maintenance	(20,779)	(17,989)	16 %
Operation and maintenance	(6,545)	(7,826)	(16)%
Consumables	(21,789)	(19,270)	13 %
Equipment rental	(7,580)	(8,127)	(7)%
Transportation costs	(4,021)	(3,383)	19 %
Field camp	(4,070)	(4,386)	(7)%
Safety and insurance costs	(3,745)	(4,216)	(11)%
Personnel transportation	(2,480)	(2,397)	3 %
Consultant fees	(2,133)	(1,732)	23 %
Gas plant costs	(1,680)	(2,596)	(35)%
Non-operated blocks costs	(12,650)	(4,941)	156 %
Crude oil stock variation	6,449	(1,271)	(607)%
Purchased crude oil	(7,929)	—	100 %
Other costs	(4,471)	(4,639)	(4)%
Total	**(359,779)**	**(212,790)**	**69 %**

	Year ended December 31,									
	2022						2021			
	Colombia	Chile	Brazil	Argentina	Ecuador	Other	Colombia	Chile	Brazil	Argentina
	(in thousands of US$)									
By country										
Royalties	(60,314)	(1,165)	(1,546)	(273)	—	—	(33,385)	(770)	(1,575)	(4,270)
Economic rights	(188,989)	—	—	—	—	—	(72,956)	—	(67)	—
Staff costs and share-based payments	(10,647)	(3,180)	(5)	(199)	(38)	—	(9,490)	(3,590)	(5)	(3,909)
Well and facilities maintenance	(13,670)	(5,029)	(1,732)	(157)	(191)	—	(13,118)	(2,162)	(867)	(1,842)
Operation and maintenance	(6,240)	—	—	(305)	—	—	(4,813)	—	—	(3,013)
Consumables	(19,727)	(1,917)	—	(129)	(16)	—	(17,022)	(1,151)	—	(1,097)
Equipment rental	(7,372)	—	—	(60)	(148)	—	(6,682)	(608)	—	(837)
Transportation costs	(3,163)	(848)	—	(7)	(3)	—	(2,606)	(691)	—	(86)
Field camp	(3,239)	(795)	—	(36)	—	—	(3,546)	(438)	—	(402)
Safety and insurance costs	(3,321)	(195)	(217)	(12)	—	—	(3,462)	(222)	(195)	(337)
Personnel transportation	(2,334)	(83)	—	(54)	(9)	—	(2,035)	(167)	—	(195)
Consultant fees	(2,067)	—	(3)	(12)	(51)	—	(1,622)	—	(13)	(97)
Gas plant costs	—	(241)	(1,375)	(64)	—	—	(166)	(360)	(1,471)	(599)
Non-operated blocks costs	(6,618)	—	(215)	—	(5,817)	—	(4,742)	—	(199)	—
Crude oil stock variation	3,652	(235)	—	(21)	3,053	—	(1,286)	(12)	—	27
Purchased crude oil	—	—	—	—	—	(7,929)	—	—	—	—
Other costs	(3,577)	(438)	(206)	(250)	—	—	(1,453)	(879)	(204)	(2,103)
Total	**(327,626)**	**(14,126)**	**(5,299)**	**(1,579)**	**(3,220)**	**(7,929)**	**(178,384)**	**(11,050)**	**(4,596)**	**(18,760)**

Consolidated production and operating costs increased 69%, from US$212.8 million for the year ended December 31, 2021, to US$359.8 million for the year ended December 31, 2022, primarily due to higher cash royalties and economic rights because of higher international prices.

Production and operating costs in Colombia increased by 84%, to US$327.6 million for the year ended December 31, 2022, as compared to US$178.4 million for the year ended December 31, 2021, primarily due to higher royalties and economic rights of US$143.0 million, in line with higher oil prices.

Production and operating costs in Chile increased by 28% to US$14.1 million due to well intervention and maintenance activities in the Fell Block. Operating costs per boe increased to US$16.1 per boe in 2022 from US$12.3 per boe in 2021.

Production and operating costs in Brazil increased by 15%, to US$5.3 million for the year ended December 31, 2022, as compared to the year ended December 31, 2021, mainly resulting from maintenance activities in the Manati Block. Operating costs per boe increased to US$7.4 for the year ended December 31, 2022, from US$4.6 per boe for the year ended December 31, 2021.

Production and operating costs in Argentina amounted to US$1.6 million for the year ended December 31, 2022, as compared to US$18.8 million for the year ended December 31, 2021, due to the divestment of the Aguada Baguales, Puesto Touquet and El Porvenir Blocks on January 31, 2022.

Production and operating costs in Ecuador amounted to US$3.2 million for the year ended December 31, 2022.

Purchases of crude oil for the trading operation performed by the holding company, GeoPark Limited, amounted to US$7.9 million for the year ended December 31, 2022.

Geological and geophysical expenses

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
Colombia	(7,105)	(3,450)	(3,655)	106 %
Chile	(116)	(74)	(42)	57 %
Brazil	—	—	—	— %
Argentina	(780)	(998)	218	(22)%
Ecuador	(297)	—	(297)	100 %
Other	(2,231)	(3,369)	1,138	(34)%
Total	**(10,529)**	**(7,891)**	**(2,638)**	**33 %**

Geological and geophysical expenses increased by 33%, from US$7.9 million for the year ended December 31, 2021, to US$10.5 million for the year ended December 31, 2022, primarily as the result of higher costs related to resuming the exploratory activities in Colombia.

Administrative costs

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
Colombia	(24,886)	(20,441)	(4,445)	22 %
Chile	(1,991)	(1,694)	(297)	18 %
Brazil	(1,526)	(1,349)	(177)	13 %
Argentina	(3,307)	(4,787)	1,480	(31)%
Ecuador	(1,267)	(1,913)	646	(34)%
Other	(17,047)	(16,644)	(403)	2 %
Total	**(50,024)**	**(46,828)**	**(3,196)**	**7 %**

Administrative costs increased by 7%, from US$46.8 million for the year ended December 31, 2021, to US$50.0 million for the year ended December 31, 2022, primarily as the result of the increase in travel expenses and other costs related to projects that had been postponed due to the COVID-19 pandemic and the accrual of share-based programs granted in 2022.

Selling expenses

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
Colombia	(5,887)	(7,033)	1,146	(16)%
Chile	(328)	(318)	(10)	3 %
Brazil	—	—	—	— %
Argentina	(104)	(1,379)	1,275	(92)%
Ecuador	(1,676)	—	(1,676)	100 %
Total	**(7,995)**	**(8,730)**	**735**	**(8)%**

Selling expenses decreased by 8%, from US$8.7 million for year ended December 31, 2021, to US$8.0 million for the year ended December 31, 2022, primarily due to: (1) differences in accounting for different points of sale in Colombia and (2) the divestment of the Aguada Baguales, Puesto Touquet and El Porvenir Blocks on January 31, 2022. The effect was partially offset by the first oil sales in Ecuador due to the successful drilling campaign in the Perico Block during the year.

Commodity risk management contracts

We recorded a loss of US$70.2 million related to commodity risk management contracts for the year ended December 31, 2022, and a loss of US$109.2 million for the year ended December 31, 2021.

Consolidated commodity risk management contracts refer to two different components, a realized and an unrealized portion. The realized loss of US$83.2 million for the year ended December 31, 2022, compared to a US$109.7 million loss for the year ended December 31, 2021, reflected Brent oil prices above ceiling prices of the commodity risk management contracts settled during the respective periods. The unrealized gain was US$13.0 million for the year ended December 31, 2022, compared to US$0.5 million gain for the year ended December 31, 2021.

Depreciation

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
Colombia	(78,775)	(61,279)	(17,496)	29 %
Chile	(14,076)	(14,275)	199	(1)%
Brazil	(2,796)	(4,082)	1,286	(32)%
Argentina	(254)	(9,130)	8,876	(97)%
Ecuador	(788)	(200)	(588)	294 %
Other	(3)	(3)	—	— %
Total	**(96,692)**	**(88,969)**	**(7,723)**	**9 %**

Depreciation charges increased by 9% from US$89.0 million for the year ended December 31, 2021, to US$96.7 million for the year ended December 31, 2022, primarily due to an increase in the depreciation cost per boe in Colombia as a consequence of lower proved and probable reserves in the CPO-5 and the Llanos 34 Blocks, partially offset by the decrease in the depreciation charge in Argentina due to the divestment of the Aguada Baguales, Puesto Touquet and El Porvenir Blocks on January 31, 2022.

Operating profit

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
Colombia	443,584	228,983	214,601	94 %
Chile	(728)	(29,160)	28,432	(98)%
Brazil	10,521	9,502	1,019	11 %
Argentina	923	(567)	1,490	(263)%
Ecuador	(1,033)	(2,188)	1,155	(53)%
Other	(24,190)	(20,761)	(3,429)	17 %
Total	**429,077**	**185,809**	**243,268**	**131 %**

We recorded an operating profit of US$429.1 million for the year ended December 31, 2022, compared to US$185.8 million for the year ended December 31, 2021, as a result of the reasons described above.

In 2022, we recorded a write-off of unsuccessful exploration efforts of US$25.8 million that corresponded to exploration costs incurred in previous years in the Tacacho and Terecay Blocks (Colombia) for which no additional work would be performed, four exploratory wells drilled in the CPO-5, Platanillo, Llanos 34 and Llanos 94 Blocks (Colombia), and certain exploration costs incurred in the Espejo Block (Ecuador). No impairment losses were recognized during 2022.

Financial results

Net financial results decreased 14% to US$53.9 million for the year ended December 31, 2022, as compared to US$62.5 million for the year ended December 31, 2021, mainly resulting from the deleveraging process executed during 2021 and 2022 that resulted in significant debt reduction with extended maturities and lower costs of debt.

Foreign exchange gain

Foreign exchange difference was a gain of US$5.0 million for the year ended December 31, 2021, compared to a gain of US$19.7 million for the year ended December 31, 2022. The gain in both years mainly corresponds to the effect of the devaluation of the local currency in Colombia on the liabilities held in that currency, such as the income tax payable, the provision for asset retirement obligation and other environmental liabilities, and the lease liabilities.

Profit before income tax

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
Colombia	460,561	210,472	250,089	119 %
Chile	(2,491)	(30,284)	27,793	(92)%
Brazil	11,119	8,714	2,405	28 %
Argentina	(4,337)	(2,865)	(1,472)	51 %
Ecuador	(1,469)	(2,967)	1,498	(50)%
Other	(68,474)	(54,672)	(13,802)	25 %
Total	**394,909**	**128,398**	**266,511**	**208 %**

For the year ended December 31, 2022, we recorded a profit before income tax of US$394.9 million, compared to a profit of US$128.4 million for the year ended December 31, 2021, primarily due to the reasons mentioned above.

Income tax expense

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
Colombia	(162,565)	(61,074)	(101,491)	166 %
Chile	(525)	(4,865)	4,340	(89)%
Brazil	(3,566)	2,700	(6,266)	(232)%
Argentina	—	(4,032)	4,032	(100)%
Ecuador	(780)	—	(780)	100 %
Other	(3,038)	—	(3,038)	100 %
Total	**(170,474)**	**(67,271)**	**(103,203)**	**153 %**

Our effective tax rate was 43% for the year ended December 31, 2022, compared to 52% in 2021. The decrease in the effective tax rate was primarily due to higher taxable profit during 2022. The effective tax rate in 2022 includes the effect of the tax reform in Colombia as well as the effect of the devaluation of the local currency in Colombia on the tax bases of property, plant and equipment. Both effects have no impact on the current income tax for 2022, but they affect the calculation of the deferred income tax.

Profit for the year

	Year ended December 31,		Change from prior year	
	2022	2021		%
	(in thousands of US$, except for percentages)			
Colombia	297,996	149,398	148,598	99 %
Chile	(3,016)	(35,149)	32,133	(91)%
Brazil	7,553	11,414	(3,861)	(34)%
Argentina	(4,337)	(6,897)	2,560	(37)%
Ecuador	(2,249)	(2,967)	718	(24)%
Other	(71,512)	(54,672)	(16,840)	31 %
Total	**224,435**	**61,127**	**163,308**	**267 %**

For the year ended December 31, 2022, we recorded a net profit of US$224.4 million as a result of the reasons described above, compared to a net profit of US$61.1 million for the year ended December 31, 2021.

Year ended December 31, 2021 compared to year ended December 31, 2020

For a discussion of the results of our operations for the year ended December 31, 2021, compared to the year ended December 31, 2020, please refer to "Item 5.—A. Operating Results—Results of Operations for the Year Ended December 31, 2021, compared to the year ended December 31, 2020" in our Annual Report on Form 20-F for the year ended December 31, 2021.

B. Liquidity and capital resources

Overview

Our financial condition and liquidity are and will continue to be influenced by a variety of factors, including:

- changes in oil and natural gas prices and our ability to generate cash flows from our operations;
- our capital expenditure requirements;
- the level of our outstanding indebtedness and the interest we have to pay on this indebtedness; and

- changes in exchange rates which will impact our generation of cash flows from operations when measured in US$.

We continually evaluate additional alternatives to further improve our capital structure by increasing our cash balances and/or reducing or refinancing a portion of our indebtedness. These alternatives include various strategic initiatives and potential asset sales as well as potential public or private equity or debt financings. If additional funds are obtained by issuing equity securities, our existing stockholders could be diluted. We can give no assurances that we will be able to sell any of our assets or to obtain additional financing on terms acceptable to us, or at all.

Our principal sources of liquidity have historically been contributed shareholder equity, debt financings and cash generated by our operations. We have also in the past entered into offtake and prepayment agreements.

Between 2005 and 2022, we raised approximately US$200 million in equity offerings at the holding company level and nearly US$1.5 billion through debt arrangements with multilateral agencies such as the IFC, gas prepayment facilities with Methanex, international bond issuances and bank financings, described further below, which have been used to fund our capital expenditures program and acquisitions and to increase our liquidity.

In February 2014, we commenced trading on the NYSE and raised US$98 million (before underwriting commissions and expenses), including the over-allotment option granted to and exercised by the underwriters, through the issuance of 13,999,700 common shares.

In September 2017, we issued US$425.0 million aggregate principal amount of 6.50% senior notes due 2024 (the “2024 Notes”). The net proceeds from the Notes were used by us (i) to fully repay senior secured notes due 2020 and to pay any related fees and expenses, including a call premium, and (ii) for general corporate purposes, including capital expenditures, such as the acquisition of Aguada Baguales, El Porvenir and Puesto Touquet blocks in the Neuquén Basin in Argentina and to repay existing indebtedness, including the Itaú loan.

In January 2020, we issued US$350.0 million aggregate principal amount of 5.5% senior notes due 2027 (the “2027 Notes”). The net proceeds from the Notes were used by us (i) to pay the total consideration for the acquisition of Amerisur and to pay related fees and expenses, and (ii) for general corporate purposes.

In April 2021, we executed a series of transactions that included a successful tender to purchase US$255.0 million of the 2024 Notes that was funded with a combination of cash in hand and a US$150.0 million new issuance from the reopening of the 2027 Notes. The issuance and the tender offer closed on April 23, 2021, and April 26, 2021, respectively.

The tender total consideration included the tender offer consideration of US$1,000 for each US$1,000 principal amount of the 2024 Notes plus the early tender payment of US$50 for each US$1,000 principal amount of the 2024 Notes. The tender also included a consent solicitation to align the covenants of the 2024 Notes to those of the 2027 Notes. The reopening of the 2027 Notes was priced above par at 101.875%, representing a yield to maturity of 5.117%. The debt issuance cost for this transaction amounted to US$2.0 million. The Notes are fully and unconditionally guaranteed jointly and severally by GeoPark Chile S.p.A. and GeoPark Colombia S.L.U.

Between March and July 2022, we continued our deleveraging process by repurchasing and cancelling with the trustee, a total nominal amount of US$102,876,000 of our 2024 Notes. Of this total amount, US$57,876,000 was repurchased in open market transactions at prices below the call option level and US$45,000,000 was redeemed at a redemption price stated in the indenture governing the 2024 Notes.

On June 17, 2022, we received requisite consents from holders of the 2027 Notes for certain amendments to the indenture governing the 2027 Notes. The amendments addressed the impact of adverse market conditions and related drop in the price of crude oil during 2020 on our results, which in turn negatively impacted the restricted payments builder basket, and increased and reset the general restricted payments basket in the indenture to provide us additional restricted payments capacity, giving us additional financial flexibility. Consequently, on June 27, 2022, we paid a consent fee equal to $10.00 per $1,000 to holders of the 2027 Notes that delivered their consents for the abovementioned amendments to the indenture governing the 2027 Notes.

On September 21, 2022, we fully redeemed our 2024 Notes by redeeming the remaining aggregate principal amount of US$67,124,000. Pursuant to the terms of the indenture governing the 2024 Notes, the 2024 Notes were redeemed at a redemption price equal to 101.625% of the principal amount of the 2024 Notes redeemed, plus accrued and unpaid interests.

Following the abovementioned transactions, we reduced our total indebtedness nominal amount by US$275.0 million by using the cash generated from our operations and improved our financial profile by extending our debt maturities.

Since September 2021, we have been included in the S&P Global BMI Index and sub-indexes, including the S&P Emerging BMI, the S&P Colombia BMI, the S&P Latin America BMI, and the S&P Global BMI Energy, among others.

We believe that our current operations and 2023 capital expenditures program can be funded from cash flow from existing operations and cash on hand. Should our operating cash flow decline due to unforeseen events, including delivery restrictions or a protracted downturn in oil and gas prices, we would examine measures such as capital expenditure program reductions, oil prepayment agreements, disposition of assets, or issuance of equity, among others. We believe the liquidity and capital resource alternatives available to us will be adequate to fund our operations and provide flexibility until oil prices and industry conditions improve. This includes supporting our capital expenditure program, payment of debt services and dividends and any amount that may ultimately be paid in connection with commitments and contingencies. See “Item 4. Information on the Company—B. Business Overview—2023 Strategy and Outlook.”

Capital expenditures

In the past, we have funded our capital expenditures with proceeds from equity offerings, credit facilities, debt issuances and pre-sale agreements, as well as through cash generated from our operations. We expect to incur substantial expenses and capital expenditures as we develop our oil and natural gas prospects and acquire additional assets. See “Item 4. Information on the Company –B. Business Overview—2023 Strategy and Outlook”.

In the year ended December 31, 2022, we had total capital expenditures, related to purchase of property, plant and equipment, of US$168.8 million (US$139.2 million, US$11.1 million and US$18.5 million in Colombia, Chile and Ecuador, respectively).

In the year ended December 31, 2021, we had total capital expenditures, related to purchase of property, plant and equipment, of US$129.3 million (US$119.9 million, US$4.3 million, US$0.1 million and US$5.0 million in Colombia, Chile, Argentina and Ecuador, respectively).

Cash flows

The following table sets forth our cash flows for the periods indicated:

	Year ended December 31,		
	2022	**2021**	**2020**
	(in thousands of US$)		
Cash flows from (used in)			
Operating activities	467,471	216,777	168,699
Investing activities	(153,673)	(126,558)	(347,633)
Financing activities	(286,552)	(190,442)	271,145
Net increase (decrease) in cash and cash equivalents	**27,246**	**(100,223)**	**92,211**

Cash flows from operating activities

For the year ended December 31, 2022, cash flows from operating activities were US$467.5 million, a 116% increase from US$216.8 million for the year ended December 31, 2021, mainly resulting from the increase in revenues of oil reflecting higher oil and gas prices in 2022.

For the year ended December 31, 2021, cash flows from operating activities were US$216.8 million, a 28% increase from US$168.7 million for the year ended December 31, 2020, mainly resulting from the increase in revenues of oil reflecting higher oil and gas prices in 2021, partially offset by the cash payments for taxes made during 2021.

Cash flows used in investing activities

For the year ended December 31, 2022, cash flows used in investing activities were US$153.7 million, a 21% increase from US$126.6 million for the year ended December 31, 2021. This variation is primarily explained by an increase of US$39.6 million in capital expenditures related to the purchase of property, plant and equipment.

For the year ended December 31, 2021, cash flows used in investing activities were US$126.6 million, a 64% decrease from US$347.6 million for the year ended December 31, 2020. This variation is primarily explained by the fact that we did not acquire any businesses in 2021 (US$272.3 million in 2020) partially offset by an increase of US$54.0 million in capital expenditures related to the purchase of property, plant and equipment.

Cash flows (used in) from financing activities

Cash flows used in financing activities were US$286.6 million for the year ended December 31, 2022, compared to US$190.4 million from financing activities for the year ended December 31, 2021. This variation was principally related to the full redemption of the 2024 Notes plus an increase in the programs of repurchase of shares and quarterly cash distributions.

Cash flows used in financing activities were US$190.4 million for the year ended December 31, 2021, compared to US$271.1 million from financing activities for the year ended December 31, 2020. This variation was principally related to the execution of a series of transactions that included a successful tender to purchase US$255.0 million of the 2024 Notes that was funded with a combination of cash in hand and a US$150.0 million new issuance from the reopening of the 2027 Notes.

Indebtedness

As of December 31, 2022, and 2021, we had total outstanding indebtedness of US$497.6 million and US$674.1 million, respectively, as set forth in the table below.

	As of December 31,	
	2022	2021
	(in thousands of US$)	
2024 Notes	—	171,880
2027 Notes	497,642	499,893
Banco Santander	—	2,319
Total	**497,642**	**674,092**

Our material outstanding indebtedness is described below.

Notes due 2024 and 2027

General

On September 21, 2017, we issued US$425.0 million aggregate principal amount of senior notes due 2024 (the "2024 Notes"). The 2024 Notes were set to mature on September 21, 2024, and bore interest at a fixed rate of 6.50% and a yield of 6.50% per year. Interest on the Notes due 2024 was payable semi-annually in arrears on March 21 and September 21 of each year.

On January 17, 2020, we issued US$350.0 million aggregate principal amount of senior notes due 2027 (the "2027 Notes"). The Notes due 2027 mature on January 17, 2027 and bear interest at a fixed rate of 5.50% per year and a yield to maturity of 5.625%. Interest on the Notes due 2027 is payable semi-annually in arrears on January 17 and July 17 of each year.

In April 2021, we executed a series of transactions that included a successful tender to purchase US$255.0 million of the 2024 Notes that was funded with a combination of cash in hand and a US$150.0 million new issuance from the reopening of the 2027 Notes. The tender total consideration included the tender offer consideration of US$1,000 for each US$1,000 principal amount of the 2024 Notes plus the early tender payment of US$50 for each US$1,000 principal amount of the 2024 Notes. The tender also included a consent solicitation to align the covenants of the 2024 Notes to those of the 2027 Notes. The reopening of the 2027 Notes was priced above par at 101.875%, representing a yield to maturity of 5.117%. The debt issuance cost for this transaction amounted to US$2.0 million. The Notes are fully and unconditionally guaranteed jointly and severally by GeoPark Chile S.p.A. and GeoPark Colombia S.L.U.

Between March and July 2022, we continued the deleveraging process, by repurchasing and cancelling, with the trustee, a total nominal amount of US$102.9 million of our 2024 Notes. Of this total amount, US$57.9 million was repurchased in open market transactions at prices below the call option level and US$45.0 million was redeemed at a redemption price stated in the indenture governing the 2024 Notes.

On June 17, 2022, we received requisite consents from holders of the 2027 Notes for certain amendments to the indenture governing the 2027 Notes. The amendments addressed the impact of adverse market conditions and related drop in the price of crude oil during 2020 on our results, which in turn negatively impacted the restricted payments builder basket, and increased and reset the general restricted payments basket in the indenture to provide us additional restricted payments capacity, giving us additional financial flexibility. Consequently, on June 27, 2022, we paid a consent fee equal to $10.00 per $1,000 to holders of the 2027 Notes that delivered their consents for the abovementioned amendments to the indenture governing the 2027 Notes.

On September 21, 2022, we fully redeemed our 2024 Notes by redeeming the remaining aggregate principal amount of US$67.1 million. Pursuant to the terms of the indenture governing the 2024 Notes, the 2024 Notes were redeemed at a redemption price equal to 101.625% of the principal amount of the 2024 Notes redeemed, plus accrued and unpaid interests.

Following the abovementioned transactions, we reduced our total indebtedness nominal amount by US$275.0 million by using the cash generated from our operations and improved our financial profile by extending our debt maturities.

Ranking

The Notes due 2027 constitute senior unsubordinated obligations of GeoPark Limited and are guaranteed by GeoPark Chile S.p.A. and GeoPark Colombia S.L.U. (the “Guarantors”). The Notes due 2027 rank equally in right of payment with all existing and future senior obligations of GeoPark Limited and the Guarantors (except those obligations preferred by operation of law, including without limitation labor and tax claims); rank senior in right of payment to all existing and future subordinated indebtedness of GeoPark Limited and the Guarantors; and rank effectively junior to any secured obligations of GeoPark Limited, the Guarantors and their respective subsidiaries to the extent of the value of the collateral securing such obligations.

Optional redemption

We may, at our option, redeem all or part of the Notes due 2027, at the redemption prices, expressed as percentages of principal amount, set forth below, plus accrued and unpaid interest thereon (including additional amounts), if any, to the applicable redemption date, if redeemed during the 12-month period beginning on January 17 of the years indicated below:

Year	Percentage
2024	102.750 %
2025	101.375 %
2026 and after	100.000 %

Change of control

Upon the occurrence of certain events constituting a change of control, we are required to make an offer to repurchase all outstanding Notes due 2027, at a purchase price equal to 101% of the principal amount thereof plus any accrued and unpaid interest (including any additional amounts payable in respect thereof) thereon to the date of purchase. If holders of not less than 90% in aggregate principal amount of the outstanding Notes due 2027 validly tender and do not withdraw such notes and we repurchase all such notes, we may redeem the Notes due 2027 that remain outstanding following such purchase at a price in cash equal to 101% of the principal amount thereof plus accrued and unpaid interest to but excluding the date of such redemption.

Covenants

The Notes due 2027 contain customary covenants, which include, among others, limitations on the incurrence of debt and disqualified or preferred stock, restricted payments (including restrictions on our ability to pay dividends), incurrence of liens, guarantees of additional indebtedness, the ability of certain subsidiaries to pay dividends, asset sales, transactions with affiliates, engaging in certain businesses and merger or consolidation with or into another company.

In the event the Notes due 2027 receive investment-grade ratings from at least two of the following rating agencies, Standard & Poor's, Moody's and Fitch, and no default has occurred or is continuing under the indentures governing the Notes due 2027, certain of these restrictions, including, among others, the limitations on incurrence of debt and disqualified or preferred stock, restricted payments (including restrictions on our ability to pay dividends), the ability of certain subsidiaries to pay dividends, asset sales and certain transactions with affiliates will no longer be applicable.

The indenture governing our Notes includes certain tests that must be satisfied before incurring additional debt, as well as other matters, and which provide among other things, that the net debt to EBITDA ratio should not exceed 3.25 and the EBITDA to interest ratio should exceed 2.5. Failure to comply with the incurrence test covenants does not trigger an event of default. However, this situation may limit our capacity to incur additional indebtedness, as specified in the indenture governing the Notes, other than certain categories of permitted debt. We must test incurrence covenants before incurring additional debt or performing certain corporate actions including but not limited to making dividend payments, restricted payments and others (in each case with certain specific exceptions).

Events of default

Events of default under the indentures governing the Notes due 2027 include: the nonpayment of principal when due; default in the payment of interest, which continues for a period of 30 days; failure to make an offer to purchase and thereafter accept tendered notes following the occurrence of a change of control or as required by certain covenants in the indentures governing the Notes due 2027; cross payment default relating to debt with a principal amount of US$40.0 million or more, and cross-acceleration default following a judgment for US$40.0 million or more; bankruptcy and insolvency events; and invalidity or denial or disaffirmation of a guarantee of the notes. The occurrence of an event of default would permit or require the principal of and accrued interest on the Notes due 2027 to become or to be declared due and payable.

Banco Santander

In October 2018, we executed a loan agreement with Banco Santander for Brazilian Real R$77.6 million (equivalent to US$20.0 million at the moment of the loan execution) to repay an existing US$-denominated intercompany loan. The interest rate applicable to this loan is the CDI plus 2.25% per annum. CDI represents the average rate of all inter-bank overnight transactions in Brazil. In September 2020, we executed the refinancing of the outstanding principal for Brazilian Real R$19.4 million (equivalent to US$3.4 million at the moment of the refinancing execution) to be paid in three equal semi-annual instalments. The loan was fully repaid in October 2022.

Off-balance sheet arrangements

We did not have any off-balance sheet arrangements as of December 31, 2022, or as of December 31, 2021.

C. Research and development, patents and licenses, etc.

See "Item 4. Information on the Company——B. Business Overview" and "Item 4. Information on the Company—B. Business Overview—Title to properties."

D. Trend information

For a discussion of Trend information, see "—A. Operating Results—Factors affecting our results of operations" and "Item 4. Information on the Company—B. Business Overview—2023 Strategy and Outlook."

E. Critical accounting policies and estimates

We prepare our Consolidated Financial Statements in accordance with IFRS and the interpretations of the IFRS Interpretations Committee ("IFRIC"), as issued by the IASB. The preparation of the financial statements requires us to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosure of contingent assets and liabilities. We continually evaluate these estimates and assumptions based on the most recently available information, our own historical experience and various other assumptions that we believe to be reasonable under the circumstances. Since the use of estimates is an integral component of the financial reporting process, actual results could differ from those estimates.

An accounting policy is considered critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time such estimate is made, and if different accounting estimates that reasonably could have been used, or changes in the accounting estimates that are reasonably likely to occur periodically, could materially impact the financial statements. We believe that the following accounting policies represent critical accounting policies as they involve a higher degree of judgment and complexity in their application and require us to make significant accounting estimates. The following descriptions of critical accounting policies and estimates should be read in conjunction with our Consolidated Financial Statements and the accompanying notes and other disclosures.

Reserves estimates

The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. The estimation of economically recoverable oil and natural gas reserves and related future net cash flows was performed based on the Reserve Report as of December 31, 2022, prepared by DeGolyer and MacNaughton Corp., an independent international oil and gas consulting firm based in Dallas, Texas, in line with the principles contained in the Society of Petroleum Engineers (SPE) and the Petroleum Resources Management Reporting System (PRMS) framework. It incorporates many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies;
- tax rates by jurisdiction, and
- future development and operating costs.

Our management believes these factors and assumptions are reasonable based on the information available to them at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Such changes may impact the Group's reported financial position and results, which include: (a) the carrying value of exploration and evaluation assets; oil and gas properties and other property, plant and equipment; which may be affected due to changes in estimated future cash flows, (b) depreciation and amortization charges in the Consolidated Statement of Income, which may change where such charges are determined using the unit of production method, or where the useful life of the related assets change, (c) provisions for abandonment that may require revision where changes to reserves estimates affect expectations about when such activities will occur and the associated cost of these activities and, (d) the recognition and carrying value of deferred income tax assets that may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets.

Cash flow estimates for impairment assessments

Cash flow estimates for impairment assessments of non-financial assets require assumptions about two primary elements: future prices and reserves. Estimates of future prices require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility. The Group's forecasts for oil and gas revenues are based on prices derived from future price forecasts amongst industry analysts and internal assessments. Estimates of future cash flows are generally based on assumptions of long-term prices and operating and development costs. Given the significant assumptions required and the possibility that actual conditions may differ, management considers the assessment of impairment to be a critical accounting estimate.

For further information related to impairment of property, plant and equipment, please see Note 37 to our Consolidated Financial Statements.

Exploration and evaluation expenditures

The Group adopts the successful efforts method of accounting. Our management makes assessments and estimates regarding whether an exploration and evaluation asset should continue to be carried forward as such when insufficient information exists. This assessment is made on a quarterly basis considering the advice from qualified experts.

The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement to determine whether future economic benefits are likely from future either exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is, in itself, an estimation process that involves varying degrees of uncertainty depending on how the resources are classified. These estimates directly impact when the Group defers exploration and evaluation expenditure. The deferral policy requires management to make certain estimates and assumptions about future events and circumstances, in particular, whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalized amount is written-off in the Consolidated Statement of Income in the period when the new information becomes available.

Depreciation of oil and gas assets

Oil and gas assets held in property plant and equipment are mainly depreciated on a unit of production ("UOP") basis at a rate calculated by reference to proven and probable reserves and incorporating the estimated future cost of developing and extracting those reserves. Future development costs are estimated using assumptions as to the numbers of wells required to produce those reserves, the cost of the wells and future production facilities. This results in a depreciation charge proportional to the depletion of the anticipated remaining production from the block.

The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the block at which the asset is located. These calculations require the use of estimates and assumptions, including the amount of recoverable reserves and estimates of future capital expenditure. The calculation of the UOP rate of depreciation will be impacted to the extent that actual production in the future is different from current forecast production based on total proved and probable reserves, or future capital expenditure estimates change. Changes to proved and probable reserves could arise due to changes in the factors or assumptions used in estimating reserves, including: (a) the effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions and (b) unforeseen operational issues.

Asset retirement obligations

Obligations related to the abandonment of wells once operations are terminated may result in the recognition of significant liabilities. We record the fair value of the liability for asset retirement obligations in the period in which the wells are drilled. When the liability is initially recognized, the cost is also capitalized by increasing the carrying amount of the related asset. Over time, the liability is accreted to its present value at each reporting date, and the capitalized cost is depreciated over the estimated useful life of the related asset. Estimating the future abandonment costs is difficult and requires management to make estimates and judgments because most of the obligations will be settled after many years. Technologies and costs are constantly changing, as well as political, environmental, health, safety and public relations considerations. Consequently, the timing and future cost of abandonment are subject to significant modification. Any change in the variables underlying our assumptions and estimates can have a significant effect on the liability and the related capitalized asset. The present value of future costs necessary for well abandonment is calculated for each area at the present value of the estimated future expenditure. The liability recognized is based upon estimated future abandonment costs, wells subject to abandonment, time to abandonment, and future inflation rates.

The expected timing, extent and amount of expenditure may also change, for example, in response to changes in oil and gas reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

The provision at reporting date represents management’s best estimate of the present value of the future abandonment costs required.

Contingencies

From time to time, we may be subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, tax, environmental and health & safety matters. For example, from time to time, the Company receives notices of environmental, health and safety violations. Based on what our Management currently knows, such claims are not expected to have a material impact on the Consolidated Financial Statements.

ITEM 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

A. Directors and senior management

Board of directors

Our board of directors is currently composed of nine members. Our directors are elected by shareholders annually at the Company's annual general meeting and can hold office for such term as the shareholders may determine or, in the absence of such determination, until the next annual general meeting or until their successors are elected or appointed or their office is otherwise vacated. The term for the current directors expires on the date of our next annual general meeting of shareholders to be held in 2023.

The current members of the board of directors were appointed at our annual general meeting held on July 15, 2022. The table below sets forth certain information concerning our current board of directors. All ages are current as of March 30, 2023.

Name	Position	Age	At the Company since
Sylvia Escovar Gómez (1)	Chair and Director	61	2020
James F. Park	Deputy Chairman, Director and Co-founder	67	2002
Robert Bedingfield (1)(2)	Director	74	2015
Constantin Papadimitriou (1)(2)	Director	62	2018
Somit Varma (1)	Director	62	2020
Brian F. Maxted (1)	Director	65	2022
Carlos E. Macellari (1)(2)	Director	69	2022
Marcela Vaca	Director	54	2012
Andrés Ocampo	Chief Executive Officer and Director	45	2010

(1) Independent director under SEC Audit Committee rules.
(2) Member of the Audit Committee.

Biographical information of the current members of our board of directors is set forth below. Unless otherwise indicated, the current business addresses for our directors is Calle 94 no. 11-30, floor 8, 9, 10 and 11, Bogotá, Colombia.

Sylvia Escovar Gómez has been a member of our board of directors since June 2020 and was appointed as Chair on June 8, 2021. An economist by training, she received her undergraduate degree from the Universidad de los Andes in Colombia. She has had a long and prestigious career in both the public and private sectors, having worked for the World Bank, the Central Bank of Colombia and the Colombian National Department of Planning. Previously, she served as Deputy Secretary of Education and Deputy Secretary of Finance for Bogota's government as well as Vice President of Finance of Fiduciaria Bancolombia. Ms. Escovar was the CEO of Terpel S.A., a fuel distribution company that operates in Colombia, Ecuador, Panama, Peru and the Dominican Republic from 2012 until December 2020. In 2014, Ms. Escovar was named the top businessperson of the year by Portafolio, Colombia's leading financial daily. In 2018, she received the National Order of Merit for spearheading private sector support for peacebuilding and reconciliation in Colombia. And in 2020, she was the only woman on the Corporate Reputation Business Monitor's list of Colombian leaders with the best reputation to rank in the top 10. Ms. Escovar's other Board memberships include Grupo Bancolombia, Empresas de Teléfonos de Bogotá, Organización Corona S.A. and Compañía de Medicina EPS Sanitas, where she serves as Chairperson of the board with strategic and external relations functions.

James F. Park since co-founding the Company in 2002, has served for 20 years as our Chief Executive Officer until his announced retirement effective June 30, 2022. He initially funded, built the team, and led the strategy and growth of GeoPark from its small footprint at the southern tip of South America into becoming one of the leading oil and gas companies operating across Latin America today. He continues to serve as Vice Chair of our board of directors and advisor to the team. Beginning as a drilling rig roughneck in his teenage years, Mr. Park has more than 50 years of experience in all phases of the upstream oil and gas business, with a record of achievement in the acquisition, technical operation, and management of international projects and teams across the globe - including projects in North America, Central America, South America, Asia, Europe, Africa, and the Middle East - and with a successful emphasis on people, communities, and the environment. He earned a Bachelor of Science in Geophysics from the University of California at Berkeley and previously worked as a research scientist focused on earthquakes and tectonics at the University of Texas. Mr. Park is a member of the board of directors of GoodRock LLC and Spark Resources LLC and is a former Board member of the humanitarian non-profit SEE (Surgical Eye Expeditions) International, and the service and advocacy non-profit Girls, Inc. He is a member of the AAPG and SPE, has a degree in environmental management, and has lived in Latin America since 2002.

Robert Bedingfield has been a member of our board of directors since March 2015. He holds a degree in Accounting from the University of Maryland and is a Certified Public Accountant. Until his retirement in June 2013, he was one of Ernst & Young's most senior Global Lead Partners with more than 40 years of experience, including 32 years as a partner in Ernst & Young's accounting and auditing practices, as well as serving on Ernst & Young's Senior Governing Board. He has extensive experience serving Fortune 500 companies; including acting as Lead Audit Partner or Senior Advisory Partner for Lockheed Martin, AES, Gannett, General Dynamics, Booz Allen Hamilton, Marriott and the US Postal Service. Since 2000, Mr. Bedingfield has been a Trustee, and at times an Executive Committee Member, and the Audit Committee Chair of the University of Maryland at College Park Board of Trustees. Mr. Bedingfield served on the National Executive Board (1995 to 2003) and National Advisory Council (since 2003) of the Boy Scouts of America. Since 2013, Mr. Bedingfield has also served as Board Member and Chairman of the Audit Committee of NYSE-listed Science Applications International Corp (SAIC). Mr. Bedingfield will become age ineligible to serve on SAIC's board on June 7, 2023.

Constantin Papadimitriou has been a member of our board of directors since May 2018. He is a respected and successful international investor and businessman, with more than 30 years of investment experience in global capital markets and in resource and industrial projects and was an early investor in GeoPark. Mr. Papadimitriou is currently the Head of General Oriental Investments S.A., the Investment Manager of the Cavenham Group of Funds. During his tenure at the Cavamont group, Mr. Papadimitriou was responsible for Treasury Management, the Private Equity Portfolio as well as representing the group on the Boards of associated companies including investments in the oil and gas, mining, real estate and gaming sectors (including Basic Petroleum, a Nasdaq-listed Guatemalan oil and gas company). He is also founding partner of Diorasis International, a company focusing on investments in Greece and the broader Balkans and he also chairs the Greek Language School of Geneva and Lausanne. Mr. Papadimitriou holds an Economics and Finance degree and a post-graduate Diploma in European Studies from Geneva University.

Somit Varma has been a member of our board of directors since August 2020. He has been a proven and respected investor in oil, gas, mining and infrastructure projects across the globe for more than three decades. During his time at the International Finance Corporation (IFC), he was the Global Head of Oil, Gas, Mining and Chemicals, Chairman of the IFC Oil, Gas, Mining and Chemicals Investment Committee and Chairman of the Global Gas Flaring Reduction Partnership. From 2011 until July 2020, Mr. Varma was a Managing Director of the Energy Group at Warburg Pincus LLC, one of the world's premier private equity firms. Throughout his tenure at Warburg Pincus, Mr. Varma served on the boards of several international energy companies where he worked with management teams on a diverse set of issues including new acquisitions, strategic partnerships, capital allocation, risk management, succession planning, and growing and mentoring teams. Mr. Varma is Chairman of the Energy and Infrastructure Council of EMPEA, the global industry association for private capital in emerging markets. He is also currently an advisor to a global private equity firm and a family office. Mr. Varma earned his MBA at Boston University before attending the Executive Development Program at Harvard Business School.

Brian F. Maxted has been a member of our board of directors since July 2022. He holds a bachelor's degree in geology from the University of Sheffield and a master's degree in organic geochemistry and petrology from the University of Newcastle-upon-Tyne. Mr. Maxted is a proven oil and gas finder, private equity entrepreneur and public company leader in the upstream E&P business, with a global track record of significant basin and play discoveries over 30 years. He spent the first part of his professional life from the late 1970s working for BP in locations including Europe, Africa, North America and South America, where he was involved in the discovery of Colombia's giant Cusiana and Cupiagua oil fields in the early 1990s. During the second half of his career from the mid-1990s through the 2010s Mr. Maxted held various exploration leadership roles for US-based independents, including Triton Energy and Hess Corporation. In 2003, Mr. Maxted became a founding partner and later the CEO/CXO and Board Director of Kosmos Energy. Mr. Maxted retired from Kosmos in 2019 and established Limatus Energy Advisory Limited to provide strategic counsel to upstream E&P companies. In addition, he led the formation of Lapis Energy, a company focused on carbon solutions in the US Lower 48, as well as in the UK/EU and Asia-Pacific, where he currently serves as Chair of the Board.

Carlos E. Macellari has been a member of our board of directors since July 2022. He holds a bachelor's degree in geology from the Universidad Nacional de La Plata in Argentina, and a master´s degree and a PhD in geology from Ohio State University. He has over 30 years of successful exploration, development and management experience in the oil and gas industry across several continents, at Tecpetrol, Repsol YPF, Hocol, Benton Oil & Gas, Enron Oil & Gas International and Pecten International (Shell Oil). As Director of Exploration and Development for Tecpetrol, he led the subsurface team responsible for making Fortín de Piedra the largest gas producing block in Argentina, and the discovery and development of the Pendare Field in Colombia. As Worldwide Director of Geology, he also led the technical group behind Repsol's exploration success in locations such as Libya, Algeria, Pre-Salt Brazil, the Gulf of Mexico, Venezuela and Peru. He has published over 40 technical papers and has been guest lecturer in numerous international forums. He is the founder of the Journal of South American Earth Sciences, has lectured several courses in the USA, Colombia, Spain and Argentina and is currently a professor for postgraduate students at Universidad Nacional de La Plata. At present he is an independent consultant on oil and gas exploration and production after founding and managing Andes Energy Consulting, and since 2020 he has been a Board member at Inverban, Tecpetrol Investments, Tecpetrol Servicios and Suizum.

Marcela Vaca joined GeoPark as Director for Colombia in August 2012 and has served as a member of our board of directors since July 2022. She has more than 20 years of experience in planning, legal, environmental and social articulation and management of hydrocarbon exploration and production projects in Colombia and elsewhere in Latin America. She joined GeoPark in 2012 and currently serves as General Director, responsible for overseeing all the Company's assets. Under her leadership, GeoPark has become one of the leading oil and gas companies in Colombia. She plays a crucial role in advancing GeoPark's diversity, equality and inclusion efforts, and promotes female empowerment as a key to the economic development of Latin America. Prior to joining our company, for nine years Ms. Vaca was the CEO of the Hupecol Group, where her achievements included leading the development of the Caracara field and the construction of the Jaguar–Santiago Pipeline. From November 2000 to June 2003, she worked as Legal, Administrative and External Affairs Manager at GHK Company Colombia. Bloomberg Linea includes Ms. Vaca in its 500 most influential people in Latin America, and in 2020, 2021 and 2022 Forbes named her as one of the 50 most powerful women in Colombia. Ms. Vaca was a member of the board of directors of the Colombian Oil Association (ACP, Asociación Colombiana de Petróleo) from 2010 to 2021 and served as Chair of the Board until March 2022. Marcela graduated in Law with a specialization in Commercial Law from the Pontificia Universidad Javeriana in Colombia and is a Fulbright Scholar with a Summa Cum Laude Master (LLM) from Georgetown University in the USA.

Andrés Ocampo has served as our Chief Executive Officer and as a member of our board of directors since July 2022. He previously served as our Chief Financial Officer (from November 2013 through June 2022) and Director of Growth and Capital Markets (from January 2011 through October 2013), and has been with our company since July 2010. Mr. Ocampo holds a Bachelor's degree in Economics from Universidad Católica Argentina, has more than 17 years of experience in business and finance. Andrés has been instrumental in helping GeoPark reach some of its greatest milestones, including its entry into Colombia and Brazil, the IPO on the New York Stock Exchange, the acquisition of Amerisur Resources and the recent significant acreage expansion in Colombia. Our board of directors appointed Mr. Ocampo to serve as Chief Executive Officer of the Company effective July 1, 2022, by virtue of his wide experience in business management and finance together with his character, vision, knowledge of the Company and his proven ability to lead successful teams. Before joining our company, Mr. Ocampo worked at Crédit Agricole Corporate & Investment Bank and Citigroup, focusing on the oil and gas and commodities industries.

Senior management

Our senior management is responsible for the management and representation of our company. The table below sets forth certain information concerning our senior management. All ages are current as of March 30, 2023.

Name	Position	Age	At the Company since
Andrés Ocampo	Chief Executive Officer and Director	45	2010
Verónica Dávila	Chief Financial Officer	40	2016
Augusto Zubillaga	Chief Technical Officer	53	2006
Rodolfo Martín Terrado	Chief Operating Officer	48	2018
Mónica Jiménez	Chief Strategy, Sustainability and Legal Officer	47	2022
Agustina Wisky	Chief People Officer	46	2002

Biographical information of the members of our senior management is set forth below. Unless otherwise indicated, the current business addresses for members of our senior management is Calle 94 no. 11-30, floor 8, 9, 10 and 11, Bogotá, Colombia.

Verónica Dávila has served as our Chief Financial Officer since July 2022. She previously served as our Commercial Director from December 2016 through June 2022, and she was in charge of managing GeoPark's oil and gas sales and transportation strategy, negotiating key financial agreements and supporting the development of the Company's overall financial strategy. Mrs. Dávila holds a Bachelor's degree in Economics from Universidad Católica Argentina. She is a highly experienced financial leader with a strong banking background and deep understanding of oil and gas market dynamics. She has over 15 years' experience in the commodities and financial sectors. Prior to joining GeoPark, she spent 10 years at Goldman Sachs in the investment banking division and at the commodities sales and trading arm in New York.

Augusto Zubillaga has served as our Chief Technical Officer since July 2022. He previously served in other management positions throughout the Company including as Chief Operating Officer, Operations Director, Argentina Director and Production Director. He is a petroleum engineer with more than 26 years of experience in production, engineering, well completions, corrosion control, reservoir management and field development. He has a degree in petroleum engineering from the Instituto Tecnológico de Buenos Aires. Prior to joining our company, Mr. Zubillaga worked for Petrolera Argentina San Jorge S.A. and Chevron San Jorge S.A. At Chevron San Jorge S.A., he led multi-disciplinary teams focused on improving production, costs and safety, and was the leader of the Asset Development Team, which was responsible for creating the field development plan and estimating and auditing the oil and gas reserves of the Trapial field in Argentina. Mr. Zubillaga was also part of a Chevron San Jorge S.A. team that was responsible for identifying business opportunities and working with the head office on the establishment of best business practices. He has authored several industry papers, including papers on electrical submersible pump optimization, corrosion control, water handling and intelligent production systems.

Rodolfo Martín Terrado has served as our Chief Operating Officer since July 2022. He previously served as our Director of Operations since he joined GeoPark in August 2018. Mr. Terrado has more than 25 years of experience in in the oil industry, working in field development and operations. Martín has a degree in Petroleum Engineering from the Instituto Tecnológico de Buenos Aires (ITBA) and an MBA from the IAE Business School at the Universidad Austral in Buenos Aires. He is a member of the Society of Petroleum Engineers (SPE). Prior to joining GeoPark, Mr. Terrado worked for Petrolera Argentina San Jorge and Chevron San Jorge S.A. in different international operations, including in Argentina, the United States and Venezuela. Mr. Terrado previously led heavy oil operations in Venezuela assets and his prior responsibilities include waterflooding, CO_2 flooding and unconventionals.

Mónica Jiménez has served as our Chief Strategy, Sustainability and Legal Officer and Company Secretary since August 2022. She leads the definition and implementation of our strategy, ingrains sustainability (ESG) within the Company and leads the legal team. Mrs. Jiménez is an experienced attorney in corporate and international law in Canada and Colombia with extensive experience in corporate law and international commercial and investment arbitration. After living in Canada for more than 15 years, Mrs. Jiménez was Vice President of Corporate Affairs and Secretary General of Ecopetrol for six years before joining GeoPark. Mrs. Jiménez studied Law at Universidad the Los Andes, has a postgraduate degree in Civil Liability and Damages from the Universidad Externado de Colombia, and a Master of Science in Development Studies from the London School of Economics (LSE). Recognized as one of the leading in-house lawyers in Colombia by The Legal 500 GC Powerlist: Colombia 2022, Mrs. Jiménez is a current member of the International Court of Arbitration of the International Chamber of Commerce (ICC) and is on the Corporate Governance Council at the Universidad de Los Andes. She has served as a director of several organizations, and is currently on the Board of TSX-listed Mineros S.A.

Agustina Wisky is GeoPark's Chief People Officer, responsible for enriching and promoting an organizational culture based on trust, teamwork, continuous improvement, mutual respect, and diversity. Agustina has been with the Company since it was founded in 2002, and she created and has led the People department for over 15 years, guided by the principles of attracting, motivating and developing the best professionals, and ensuring the comprehensive wellbeing of staff and their families. She previously held the position of Performance Director at GeoPark. Before joining GeoPark, Agustina worked at PricewaterhouseCoopers and AES Gener in Argentina. Agustina is a Public Accountant and has a Master's degree in Human Resources from the IAE Business School of the Universidad Austral in Buenos Aires, Argentina. Thanks to Agustina's leadership in the implementation of inclusion and diversity best practices, GeoPark won the Equipares Silver Award in 2020, which is given by the Government of Colombia with technical support from the United Nations Development Program. GeoPark was furthermore included in the Bloomberg Gender-Equality Index (GEI) in 2022, which evaluates the performance of listed companies that are committed to transparency in gender reporting.

B. Compensation

Senior management and director compensation

For the year ended December 31, 2022, we paid an aggregate of US$9.3 million to the members of our board of directors for their services in all capacities. This amount includes grants of awards under our Non-Executive Director Plan, payments made to Mr. Carlos Gulisano for his services as a director and consultant until July 15, 2022, payments made to Mrs. Marcela Vaca in her capacity as a non-executive director since September 10, 2022, and payments made to Mr. James F. Park with respect to his service as the Chief Executive Officer until June 30, 2022, payments under his transition agreement (as described below) and payments as a consultant following June 30, 2022. It does not include payments made to executive director Andrés Ocampo as he only received compensation as part of the senior management team (as described below). Disclosure of compensation on an individual basis is included in Note 11 to our Consolidated Financial Statement.

During this same period, we paid an aggregate of US$7.5 million for salaries and other benefits (including with respect to grants of awards under the LTIP Executives and contingent amounts or deferred compensation accrued for the year, even if payable at a later date) to the members of our senior management for their services in all capacities. This amount includes payments made to Marcela Vaca for her services as senior manager until September 9, 2022.

Annual Bonus Program

Our Corporate Governance Guidelines set forth that the Compensation Committee will evaluate annually the performance of the Chief Executive Officer and of the key executive officers of the Company based on objective and relevant corporate goals and that the board of directors, in consultation with and at the recommendation of the Compensation Committee will review key senior officers' annual performance evaluations. In addition, the Charter of the Compensation Committee establishes that the Committee shall review and approve written annual and longer-term corporate goals and objectives relevant to the compensation of the Chief Executive Officer and other key executive officers, making sure that they are appropriately linked to the Company´s strategy.

In this regard, the Compensation Committee reviews and recommends that the board of directors approve the annual performance scorecard that contains the performance metrics and objective criteria against which the Chief Executive Officer and other key executive officers are evaluated. Depending on the performance evaluation, the amounts to be paid to the Chief Executive Officer and other key executive officers as annual bonuses are recommended by the Committee and submitted to be approved by our board of directors.

CEO Transition Agreement

On March 2022, the board of directors approved the transition of the CEO position. James F. Park served as CEO until June 30, 2022, after which, the board selected and approved Andrés Ocampo to become CEO of the Company effective as of July 1, 2022. On that date, James F. Park ceased to be an employee of the Company and continued to serve as a non-executive member of the board of directors and as a consultant of the Company, advising on M&A and strategic matters. The Company has entered into a consulting agreement with James F. Park governing his consulting services, which does not provide for payments upon a termination of service (other than previously earned or accrued amounts). Pursuant to the terms of his transition agreement, James F. Park was provided certain severance benefits, including (i) cash severance payments, payable in a combination of cash and stock, (ii) accelerated vesting of unvested equity awards and (iii) administrative support for 1-2 years, reimbursement for reasonable relocation costs and 12 months of health and life insurance premiums.

Senior Management Severance

Our board of directors determined that it is in the best interests of the Company and its shareholders to provide certain members of the Company's senior management with payments and benefits in connection with certain qualified terminations and/or in connection with certain change in control scenarios. Therefore, the board of directors approved the adoption of an Executive Termination and Change in Control Benefits Plan (the "Severance Plan"). In addition, the board of directors approved an employment agreement with our CEO, Andrés Ocampo, which provides for severance benefits consistent with those provided under the Severance Plan.

In the event of a termination of the executive's employment without cause, resignation for good reason or termination due to the executive's death or disability within 24 months following a change in control, the executive will be entitled to receive the following, subject to the execution of a release of claims: (i) cash severance in an amount equal to 2 times the sum of (x) the executive's annual base salary, (y) the average of any cash bonuses paid in the two years preceding the termination date and (z) an amount equal to the lesser of 15% of the executive's annual base salary or US$50,000; and (ii) to the extent permitted by applicable law, continued health benefits, at the Company's cost, for 12 months following their termination of employment. In addition, the Severance Plan provides that, in the event an executive has relocated at the Company's request and is terminated during the 12 months following the change in control, the executive will be provided the costs for relocation back to their home country.

In the event of a termination of the executive's employment without cause, resignation for good reason or termination due to the executive's death or disability, other than in the 24 months following a change in control, then, subject to the execution of a release of claims, the executive sill be entitled to the following benefits: (i) cash severance in an amount equal to 1.5 times (or, in the case of the CEO, 2 times) the sum of (x) the executive's annual base salary, (y) the average of any cash bonuses paid in the two years preceding the termination and (z) an amount equal to the lesser of 15% of the executive's annual base salary or US$50,000, and (ii) to the extent permitted by applicable law, continued health benefits, at the Company's cost, for 12 months following their termination of employment. In addition, the executive's unvested equity awards will accelerate pro-rata (in the case of performance equity awards, subject to achievement of the applicable performance metrics).

Pursuant to the Severance Plan, in the event of a change in control, outstanding performance equity awards will convert into a number of time-based equity awards based on actual performance through the date of the change in control and, except as set forth below, will vest in accordance with the awards' original schedule, subject to the executive's continued service through such date. In the event of a termination of the executive's employment without cause, resignation for good reason or termination due to the executive's death or disability within 24 months following a change in control: (i) all outstanding time-vesting equity awards will fully accelerate and vest; and (ii) performance equity awards, as converted in accordance with clause (i) above, will fully accelerate and vest. In the event that the acquiror cashes out outstanding equity awards at closing of the change in control, then, at closing, (i) performance awards will accelerate, and vest based on actual performance through the date of the change in control and (ii) all outstanding time-vesting equity awards will fully accelerate and vest.

GeoPark Limited 2018 Equity Incentive Plan

Given the expiration of our Stock Awards Plan on November 3, 2018, in December 2018, we adopted the 2018 Equity Incentive Plan (the "Plan") to motivate and reward those participating employees and executives to perform at the highest level and to further the best interests of the Company and our shareholders. The Plan is designed as an omnibus plan, pursuant to which we may grant awards in the form of options, share appreciation rights, restricted shares, restricted stock units, performance awards, other share-based awards or other cash-based awards throughout the ten (10)-year term of the Plan. Subject to adjustments as set forth in the Plan, the maximum number of shares available for issuance under the Plan is 5,000,000 shares. The applicable award documentation will set forth the terms and conditions of the awards granted under the Plan, including, but not limited to, the vesting conditions and the effect on a termination of service or a Change in Control on awards.

The following table sets forth the common share awards granted to our employees and executives under the Plan:

Number of underlying common shares outstanding	Grant date	Vesting date	Expiration date
52,058 (1)	05/07/2019	05/07/2022	03/15/2023
800,000 (2)	01/01/2020	01/02/2023	12/31/2029
44,743 (1) (3)	05/07/2020	05/07/2023	03/15/2024
73,529 (1) (3)	05/07/2021	05/07/2024	03/15/2025
58,360 (1) (3)	05/07/2022	05/07/2025	03/15/2026
174,306 (4)	06/02/2022	01/31/2023	12/31/2028
215,000 (5)	03/31/2022	03/31/2025 (6)	12/31/2028
25,000 (7)	03/31/2022	03/31/2025	12/31/2028
571,984 (8)	10/01/2022	01/02/2025	12/31/2028
197,197 (9)	02/14/2023	01/02/2026	12/31/2028
1,000,000 (10)	01/02/2023	01/02/2026	12/31/2028

(1) James F. Park received these awards as part of his long-term equity incentive compensation while serving as CEO. For further details, please see item 6.B.
(2) On November 6, 2019, our board of directors approved a share-based compensation program for approximately 800,000 shares to be granted in 2020. Considering the performance conditions, the Compensation Committee determined that only a total of 152,030 shares have vested.
(3) As part of the CEO Transition Agreement the vesting dates were accelerated, and the awards were issued in February 2023.
(4) Awards granted according with the CEO Transition Agreement.
(5) Awards corresponding to the Retention and Hiring Bonus scheme.
(6) The vesting date is March 31, 2025 or 3 years from grant date.
(7) Service agreement. The awards granted under this agreement vest in three annual installments (March 31, 2023; March 31, 2024 and March 31, 2025).
(8) Awards corresponding to the LTIP Executives. The awards will annually vest during a three-year period beginning January 1, 2022.
(9) Awards corresponding to the LTIP Executives. The vesting date of the RSUs will be annually during a three-year period and the vesting date of the PSUs will be on January 2, 2026.
(10) Awards corresponding to LTIP Employees approved on December 2022. The vesting date of the RSUs will be annually during a three-year period and the vesting date of the PSUs will be on January 2, 2026.

Currently, we have the following incentive equity programs in place under the Plan: the Stock Awards Program ("Stock Awards Program"), the Retention and Hiring Bonus Scheme, the Long-Term Incentive Program for Executives ("LTIP Executives") and the Long-Term Incentive Program for Employees ("LTIP Employees").

Employees

Stock Awards Program

In November 2019, our board of directors approved a share-based compensation program for approximately 800,000 shares to be granted in 2020. The main characteristics of the Stock Awards Programs are:

- The exercise price is equal to the nominal value of shares.
- The vesting date of the award is January 2, 2023.
- Each employee could receive between three and six monthly payments (to be pro-rated between the hiring date and the vesting date for new hires) by achieving the following conditions: continue to be an employee, the stock market price at the date of vesting should be higher than the share price at the date of grant and obtain the Group minimum production, adjusted EBITDA and reserves target for the year of vesting.

On February 17, 2023, the Compensation Committee reviewed the Company results and the performance conditions established in the program and approved that a total of 152,030 shares shall be delivered to participants, due to the fact that, throughout the vesting period the Company: i) had lower hirings than estimated; ii) not all the beneficiaries continued being employees at vesting date; and iii) the performance conditions included in the program were only partially achieved.

The awards granted in accordance with this program and approved by the Compensation Committee may be exercised by the participants from thirty days following the publication of GeoPark's Annual Report 2022.

Retention and Hiring Bonus Scheme

On March 8, 2022, our board of directors approved a pool of approximately 215,000 shares oriented for retention of key employees and new hires bonuses.

Long-Term Incentive Program to Employees ("LTIP Employees")

In December 2022, our board of directors, as per recommendation of the Compensation Committee, approved a new Long-Term Incentive program oriented to employees and new hirings. Main characteristics of the program are:

- All employees (non-top management) and new hirings are eligible.
- 3-year program, with a grant date of January 2, 2023, or the date on which the employees will be hired.
- The components of the program are the following:
    - 30% Time-based RSUs: vesting annually ratably in three equal installments.
    - 30% Company Performance: measured over three-year performance period (December 2022-December 2025).
    - 40% Absolute Performance Shares: share price at the date of vesting must be higher than the share price at the date of grant or date of hiring.
- The vesting date of the Performance Shares (Company and Absolute) will be on January 2, 2026.

Executives

Long-Term Incentive Program to Executives ("LTIP Executives")

In March 2022, our board of directors, as per recommendation of the Compensation Committee, approved a new Long-Term Incentive program oriented to senior management team. Main characteristics of the program are:

- All the senior management team is eligible.
- Grants are awarded annually for executives.
- The components of the program are the following:

- 20% Time-based Restricted Share Units (RSUs) vesting ratably in three equal installments on each of the first three anniversaries of the grant date;
- 35% Relative Performance Share Units based on relative total shareholder return (TSR) and measured over three-year performance period relative to peer group;
- 45% Absolute Performance Share Units (PSUs) based on absolute total shareholder return (TSR) and measured over three-year performance period.

In 2022, the Compensation Committee approved Grants with respect to the LTIP Executives of an estimated 571,984 total shares, to be vested during a three-year period. On January 25, 2023, the Compensation Committee determined that 246,110 shares should be delivered to the participants according to the first vesting period of such Grants.

On February 17, 2023, the Compensation Committee approved a new Grant effective as of February 14, 2023, of 197,197 shares to be vested during a three-year period.

Our directors and senior management who have received option awards or common share awards under the Equity Incentive Plan authorize the Company to deposit any common shares they have received under this Plan in our Employee Benefit Trust ("EBT"). The EBT is held to facilitate holdings and dispositions of those common shares by the participants thereof. For further details, see "–E. Share Ownership."

Non-Executive Director Plan

In August 2014, our board of directors adopted the Non-Executive Director Plan in order to grant shares to non-executive directors as part of their compensation program for serving as directors. The Non-Executive Director Plan was amended and restated in October 2016, when additional 1,000,000 shares were registered as the maximum number of shares available to be issued under this plan. In accordance with the resolutions adopted by our board of directors on May 20, 2014, our non-executive directors are paid their quarterly fees in the form of equity awards granted under the Non-Executive Director Plan. Under the Non-Executive Director Plan, the compensation committee may award common shares, restricted share units and other share-based awards that may be denominated or payable in common shares or factors that influence the value of common shares.

Potential dilution resulting from Equity Incentive Compensation Plans

In accordance with the equity awards granted by the Company under its Stock Awards Program and the Plan, as of March 9, 2023, there were approximately one million nine hundred sixty thousand outstanding shares that had been awarded but which had not yet vested, representing approximately 3.37% of the total issued share capital as of that date.

Stock Ownership Guidelines

In December 2022, to further align the interests of our executive officers with those of the Company's shareholders, our board of directors approved minimum stock ownership guidelines applicable to the Company's Chief Executive Officer, Chief Financial Officer, Chief Technical Officer, Chief Operating Officer, Chief Strategy, Sustainability and Legal Officer and Chief People Officer. Each such officer is required to hold, within five years after the adoption of the guidelines or, if later, within five years after becoming subject to the policy, a number of shares with an aggregate value of at least three times his or her annual base salary. Shares beneficially owned by the applicable officer or held in a family trust established by the applicable officer and shares underlying vested equity awards (which, in the case of stock options, are at- or in-the-money) are taken into account for purposes of determining compliance with these guidelines. Until an officer has met his or her ownership requirement, he or she is required to retain at least 50% of shares received from the vesting, settlement or exercise of equity awards (and which remain outstanding after tax withholding and payment of any applicable exercise price).

C. Board practices

Overview

Directors are expected to provide stewardship to promote the long-term success of the Company. They are expected to fulfill their fiduciary duties and duty of care in the best interests of the Company, considering the various needs of its stakeholders (shareholders, employees, communities, suppliers and clients), providing advice to and oversight of management's activities. Within its responsibilities, the board of directors oversees the company's strategic goals; financial statements, control and risk management; core values, integrity and ethical standards; management and board remuneration and succession planning, among others. On December 23, 2020, and as amended from time to time, the board of directors adopted our Corporate Governance Guidelines (available at the Company's website) to further regulate and enhance the board's corporate governance structures and processes.

Board composition

Our bye-laws and board resolutions provide that the board of directors consist of a minimum of three and a maximum of nine members. All of our directors were elected at our annual shareholders' meeting held on July 15, 2022. Their term expires on the date of our next annual shareholders' meeting, to be held in 2023. The board of directors meets regularly throughout the year, at least on a quarterly basis.

Committees of our board of directors

Our board of directors has established an Audit Committee, a Compensation Committee, a Nomination and Corporate Governance Committee, a Strategy & Risk Committee, a Technical Committee and a SPEED Committee. The composition and responsibilities of each board committee are described below. The Nomination and Corporate Governance Committee annually considers and recommends to the board of directors the membership and the chair of each board committee. Our board of directors may establish other committees to assist with its responsibilities.

Audit Committee

The Audit Committee is currently composed of three independent directors. The current members of the Audit Committee are Mr. Robert Bedingfield (who serves as Chairman of the committee), Mr. Constantin Papadimitriou and Mr. Carlos E. Macellari. Mr. Robert Bedingfield is regarded as audit committee financial expert. We have determined that Mr. Robert Bedingfield, Mr. Constantin Papadimitriou and Mr. Carlos E. Macellari are independent, as such term is defined under SEC rules applicable to foreign private issuers.

The main purposes of the Audit Committee, without prejudice of any additional objectives or functions foreseen in its charter, are to assist the board of directors in its oversight of: (i) the integrity of the Company's financial statements and the company's accounting and financial reporting processes and financial statement audits; (ii) the independent auditor's performance, qualifications and independence; (iii) the Company's compliance with legal and regulatory requirements and the company´s ethical standards; and (iv) the performance of the company´s internal audit function.

Compensation Committee

The Compensation Committee is currently composed of four independent directors. The current members of the compensation committee are Mr. Constantin Papadimitriou (who serves as Chairman of the committee), Mr. Robert Bedingfield, Mr. Brian F. Maxted and Mr. Somit Varma.

The main purposes of the Compensation Committee, without prejudice of any additional objectives or functions foreseen in its charter, are to (i) evaluate and recommend for approval by the independent members of the Board the remuneration, benefits and incentive compensation arrangements for the key executive officers of the Company; (ii) establish performance indicators against which the key executive officers of the Company will be evaluated; (iii) evaluate and review the identification, recruitment and succession planning for key officers of the Company; and (iv) review and recommend to the board of directors any changes to the remuneration of the non-executive directors of the Company.

Nomination and Corporate Governance Committee

The Nomination and Corporate Governance Committee is currently composed of three independent directors. The current members of the Nomination and Corporate Governance Committee are Mr. Somit Varma (who serves as Chairman of the committee since November 11, 2021), Ms. Sylvia Escovar and Mr. Robert Bedingfield.

The main purposes of the Nomination and Corporate Governance Committee, without prejudice of any additional objectives or functions foreseen in its charter, are to (i) review board succession planning, including identifying and selecting suitable board candidates in accordance with the criteria set forth in its charter and approved by the board of directors; (ii) review and recommend to the board of directors the membership and Chair of each board Committee; (iii) develop, review and monitor the Company's corporate governance guidelines, processes and structures; and (iv) conduct and oversee the board of directors' annual evaluation process.

Strategy & Risk Committee

The Strategy & Risk Committee was created in December 2020, and is currently composed of six directors. The current members of the Strategy & Risk Committee are Mr. James F. Park (who serves as Chairman of the committee), Mr. Constantin Papadimitriou. Mr. Somit Varma, Mr. Brian F. Maxted, Mr. Andrés Ocampo and Mr. Carlos E. Macellari.

The main purposes of the Strategy and Risk Committee, without prejudice of any additional objectives or functions foreseen in its Charter, are to assist the Board in (i) its oversight function of understanding the various key risks to which the Company is exposed, and the interlink between the Company's strategy and such risks; and (ii) its review of new strategic opportunities and transactions (including mergers, acquisitions, divestments and similar transactions).

Technical Committee

The Technical Committee is currently composed of four directors. The current members of the technical committee are Mr. Brian F. Maxted (who serves as Chairman of the committee), Mr. Carlos E. Macellari, Mr. James F. Park and Mr. Somit Varma.

The main purposes of the Technical Committee, without prejudice of any additional objectives or functions foreseen in its Charter, are to assist the Board in fulfilling its responsibilities by providing strategic oversight on specific technical matters which are beyond the scope or expertise of non-technical Board members to: (i) Optimize and assure technical decision making in existing assets to ensure business performance targets, as defined by the annual corporate scorecard, and long-range plan goals are achieved, including with respect to the design, execution and delivery of the exploration and appraisal strategy and plan, as well as the field development programs and drilling/production operations; (ii) Review and advise the Board on the technical analysis of prospective new ventures and/or in conjunction with the Strategy and Risk Committee, potential corporate merger and acquisition opportunities, as and when required. And (iii) Provide regular, timely feedback, guidance and support to the management team and technical staff on all sub-surface matters to facilitate the Board processes related to work programs and budget planning, execution and reporting, as well as people and business performance review.

SPEED Committee

The SPEED Committee is currently composed of four directors. The current members of the SPEED committee are Ms. Marcela Vaca (who serves as Chairman of the committee), Ms. Sylvia Escovar, Mr. James F. Park and Mr. Andrés Ocampo.

The main purposes of the SPEED Committee, without prejudice of any additional objectives or functions foreseen in its Charter, are to assist the Board in (i) its guidance and oversight function of the Company's strategy concerning the SPEED matters, including the safety of its operations, the initiatives to give back value to stakeholders, the wellbeing of employees, preservation of the environment, community development, and any other matters related to sustainability; and (ii) its review of the performance on the topics above.

Liability insurance

We maintain liability insurance coverage for all of our directors and officers, the level of which is reviewed annually.

D. Employees

As of December 31, 2022, we had 482 employees, representing an increase of 4.1% from December 31, 2021.

The following table sets forth a breakdown of our employees by geographic segment for the periods indicated.

	Year ended December 31,		
	2022	2021	2020
Colombia	388	321	268
Chile	49	52	57
Brazil	4	4	5
Argentina	24	74	97
Peru	—	—	5
Ecuador	8	3	2
Corporate	9	9	3
Total	**482**	**463**	**437**

From time to time, we also utilize the services of independent contractors to perform various field and other services as needed. As of December 31, 2022, 25 of our employees were represented by labor unions or covered by collective bargaining agreements. We believe that relations with our employees are satisfactory.

E. Share ownership

As of March 9, 2023, members of our board of directors and our senior management held as a group 10,133,360 of our common shares and 17.4% of our outstanding share capital.

The following table shows the share ownership of each member of our board of directors and senior management as of March 9, 2023.

[(1)] Shareholder	Common shares	Percentage of outstanding common shares
James F. Park [(1)]	8,817,251	15.2 %
Sylvia Escovar	35,475	*
Robert Bedingfield	157,645	*
Constantin Papadimitriou [(2)]	66,590	*
Somit Varma	50,210	*
Carlos Gulisano	136,086	*
Brian Maxted	4,286	*
Carlos Macellari	3,961	*
Marcela Vaca	2,801	*
Andrés Ocampo	*	*
Verónica Dávila	*	*
Augusto Zubillaga	*	*
Rodolfo Martín Terrado	*	*
Mónica Jiménez	*	*
Agustina Wisky	*	*
Pedro E. Aylwin Chiorrini	*	*
Sub-total senior management ownership of less than 1%	859,055	1.5 %
Total	**10,133,360**	**17.4 %**

* Indicates ownership of less than 1% of outstanding common shares.

(1) Held by Mr. Park directly and indirectly through GoodRock, LLC. The information set forth above and listed in the table is based solely on the disclosure set forth in Mr. Park's most recent Schedule 13G filed with the SEC on February 13, 2023. 602,400 of Mr. Park's shares have been pledged pursuant to lending arrangements.

(2) Due to Constantin Papadimitriou's position as CEO of General Oriental Investments S.A., he may be deemed to have beneficial ownership over an additional 2,175,177 shares held by Cavenham Public Growth.

Certain members of our board of directors have, since the time of our initial public offering in the U.S., entered into certain pledges of Company securities in order to access some liquidity with respect to those shares and/or to diversify their holdings. On June 29, 2021, the board of directors, as per the recommendation of the Nomination and Corporate Governance Committee, revised its Insider Trading Policy with respect to securities pledging and prohibited employees and directors from pledging Company securities in any circumstance, including by purchasing Company securities on margin or holding Company securities in a margin account. In the event that an employee or director pledged any Company securities prior to June 29, 2021, and provided that any such pledges were made in compliance with the Insider Trading Policy of the Company effective at the time such securities were pledged, the employee or director must terminate any such arrangements by June 29, 2024.

ITEM 7. MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

A. Major shareholders

The following table presents the beneficial ownership of our common shares as of March 9, 2023, except for certain shareholders whose last available data is as of December 31, 2022. The percentages reported herein are based on the shares outstanding as of March 9, 2023.

Shareholder	Common shares	Percentage of outstanding common shares
James F. Park(1)	8,817,251	15.2 %
Compass Group LLC(2)	7,525,160	13.0 %
Gerald E. O'Shaughnessy(3)	5,545,080	9.5 %
Renaissance Technologies LLC(4)	3,106,263	5.3 %
Other shareholders	33,108,118	57.0 %
Total	**58,101,872**	**100.0 %**

(1) 7,305,133 shares are held by GoodRock, LLC, which is controlled by James F. Park. The information set forth above and listed in the table is based solely on the disclosure set forth in Mr. Park's most recent Schedule 13G filed with the SEC on February 13, 2023. 602,400 of Mr. Park´s shares have been pledged pursuant to lending arrangements.
(2) The information listed in the table is based solely on the disclosure set forth in Compass Group LLC´s most recent Schedule 13G filed with the SEC on February 14, 2023.
(3) Held by Mr. O'Shaughnessy directly and indirectly through GP Investments LLP; GPK Holdings, LLC; The Globe Resources Group, Inc.; and other investment vehicles. As of November 27, 2022, 5,000,000 of Mr. O´Shaughnessy´s shares have been pledged pursuant to lending arrangements. The information listed in the table is based solely on the disclosure set forth in Mr. O´Shaughnessy's most recent Schedule 13D filed with the SEC on November 30, 2022.
(4) The information listed in the table is based solely on the disclosure set forth in Renaissance´s most recent Schedule 13G filed with the SEC on February 13, 2023.

Principal shareholders do not have any different or special voting rights in comparison to any other common shareholder.

According to our transfer agent, as of March 9, 2023, we had 14 registered shareholders, out of which 5 are registered as U.S. shareholders. Since some of the shares are held by nominees, the number of shareholders may not be representative of the number of beneficial owners.

B. Related party transactions

We have entered into the following transactions with related parties:

Executive Directors' Service Agreements

We have entered into service contracts with certain of our executive directors. See "Item 6. Directors, Senior Management and Employees—B. Compensation—Senior management and director compensation—."

For further information relating to our related party transactions and balances outstanding as of December 31, 2022, 2021 and 2020, please see Note 34 to our Consolidated Financial Statements.

C. Interests of Experts and Counsel

Not applicable.

ITEM 8. FINANCIAL INFORMATION

A. Consolidated statements and other financial information

Financial statements

See "Item 18. Financial Statements," which contains our audited financial statements prepared in accordance with IFRS.

Legal proceedings

From time to time, we may be subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, environmental, safety and health matters. For example, from time to time, we receive notice of environmental, health and safety violations. It is not presently possible to determine whether any such matters will have a material adverse effect on our consolidated financial position and results of operations.

In Brazil, GeoPark Brazil is a party to a class action filed by the Federal Prosecutor's Office regarding a concession agreement of exploratory Block PN-T-597, which the ANP initially awarded GeoPark Brazil in the 12th oil and gas bidding round held in November 2013. The Brazilian Federal Court issued an injunction against the ANP and GeoPark Brazil in December 2013 that prohibited GeoPark Brazil's execution of the concession agreement until the ANP conducted studies on whether drilling for unconventional resources would contaminate the dams and aquifers in the region. On July 17, 2015, GeoPark Brazil, at the instruction of the ANP, signed the concession agreement, which included a clause prohibiting GeoPark Brazil from conducting unconventional exploration activity in the area. Despite the clause containing the prohibition, the judge in the case concluded that the concession agreement should not be executed. Thus, GeoPark Brazil requested that the ANP comply with the decision and annul the concession agreement, which the ANP´s Board did on October 9, 2015. The annulment reverted the status of all parties to the *status quo ante*, which maintains GeoPark Brazil's right to the block.

On January 8, 2020, Amerisur received a copy of a claim form issued in the High Court of England and Wales (the "Court") by Leigh Day solicitors on behalf of a group of claimants (the "Claimants") described as members of a farming community in the department of Putumayo in Colombia. The claim stated that the Claimants seek compensation for economic and non-economic damages said to be caused by alleged environmental contamination and pollution caused by Amerisur's operations in the region. Amerisur stated that the accusations of environmental damage referenced in the claim were being investigated by Colombian authorities and to-date had been deemed to be without merit. Following court hearings held in January and February 2020, an interim freezing order was imposed on Amerisur for an amount of GBP4,465,600 of its assets located in the United Kingdom. On November 10, 2020, the freezing order was discharged by agreement between the parties as Amerisur provided alternative security in the form of a letter of credit from an international bank in the UK.

On January 12, 2021, a hearing was held, where the Court ordered the Claimants to serve the Group Particulars of Claim (the "GPoC") by February 26, 2021. During April and May 2021, the general pollution claims were struck out by the Court leaving only the claims arising from the attack on the oil-trucks on 2015. Amerisur presented its defence to the GPoC on May 21, 2021. A case management conference was held on July 7, 2021, after which the Court ordered on July 15, 2021, among others: i) to schedule a preliminary issues trial on two Colombian law issues, namely, limitation period for bringing the claims and limitation of parent company liability; and ii) to schedule a costs management conference. The costs management conference was held on October 26, 2021. The Court made a costs award in Amerisur's favour in respect of all the general pollution claims which is enforceable against the 102 Claimants whose claims had been discontinued or struck out by the Court but only after the conclusion of the proceedings and when those costs have been either assessed or agreed.

In July 2022, the preliminary issues trial hearing was held, with experts from both parties addressing their written opinions on the two Colombian law issues. On January 26, 2023, the Court ruled in favor of the Claimants in respect of the two issues, allowing the claims to continue before the Courts in London. Amerisur requested permission to appeal before the Court on the same day. On February 6, 2023, the Court issued its ruling on the written submissions, and reply submissions, filed by the parties on costs and permission to appeal, ordering Amerisur to pay the sum of GBP330,022 (equivalent to US$397,089), and refusing permission to appeal. Consequently, on February 23, 2023, Amerisur requested permission to appeal before the court of appeal.

We have recognized a provision in our Consolidated Financial Statements for GBP4,465,600 (equivalent to US$5,384,000 as of December 31, 2022) related to this contingent liability, which was originally recognized at the moment of the acquisition of Amerisur in 2020.

Dividends and dividend policy

Holders of common shares will be entitled to receive dividends, if any, paid on the common shares.

On March 31, 2022, and June 10, 2022, we paid dividends of US$0.082 per share and, on September 8, 2022, and December 7, 2022, we paid dividends of US$0.127 per share.

Because we are a holding company with no direct operations, we will only be able to pay dividends from our available cash on hand and any funds we receive from our subsidiaries. The terms of our indebtedness may restrict us from paying dividends. We have recorded accumulated losses amounting to US$81.1 million as of December 31, 2022, which further limits our ability to pay dividends in the foreseeable future.

Under the Companies Act 1981, as amended of Bermuda (the "Bermuda Companies Act"), we may not declare or pay a dividend if there are reasonable grounds for believing that we are, or would after the payment be, unable to pay our liabilities as they become due or that the realizable value of our assets would thereafter be less than our liabilities. Under our bye-laws, each common share is entitled to dividends if, as and when dividends are declared by our board of directors, subject to any preferred dividend right of the holders of any preference shares, if any.

Additionally, any decision to pay dividends in the future, and the amount of any distributions, is at the discretion of our board of directors and our shareholders, and will depend on many factors, such as our results of operations, financial condition, cash requirements, prospects and other factors. See "Item 3. Key Information—D. Risk factors—Risks related to our common shares—Any decision to pay dividends in the future, and the amount of any distributions, is at the discretion of our board of directors, and will depend on many factors, such as our results of operations, financial condition, cash requirements, prospects and other factors" and "—We are a holding company and our only material assets are our equity interests in our operating subsidiaries and our other investments; as a result, our principal source of revenue and cash flow is distributions from our subsidiaries; our subsidiaries may be limited by law and by contract in making distributions to us," as well as "Item 10. Additional Information—B. Memorandum of association and bye-laws."

B. Significant changes

A discussion of the significant changes in our business can be found under "Item 4. Information on the Company—B. Business Overview."

ITEM 9. THE OFFER AND LISTING

A. Offering and listing details

Not applicable.

B. Plan of distribution

Not applicable.

C. Markets

Our common shares have been listed on the NYSE under the symbol "GPRK" since February 7, 2014.

D. Selling shareholders

Not applicable.

E. Dilution

Not applicable.

F. Expenses of the issue

Not applicable.

ITEM 10. ADDITIONAL INFORMATION

A. Share capital

Not applicable.

B. Memorandum of association and bye-laws

The following description of our memorandum of association and bye-laws does not purport to be complete and is subject to, and qualified by reference to, all of the provisions of our memorandum of association and bye-laws.

General

We are an exempted company limited by shares incorporated under the laws of Bermuda. We are registered with the Registrar of Companies in Bermuda under registration number 33273. The rights of our shareholders will be governed by Bermuda law and by our memorandum of association and bye-laws. Bermuda company law differs in some material respects from the laws generally applicable to Delaware corporations. Below is a summary of some of those material differences.

Because the following statements are summaries, they do not discuss all aspects of Bermuda law that may be relevant to us and to our shareholders.

Share capital and bye-laws

Our share capital consists of common shares only. Our authorized share capital consists of 5,171,949,000 common shares of par value US$0.001 per share. As of March 9, 2023, there are 58,101,872 common shares outstanding. All of our issued and outstanding common shares are fully paid and non-assessable. We also have an employee incentive program, pursuant to which we have granted share awards to our senior management and employees. See "Item 6. Directors, Senior Management and Employees."

According to our bye-laws, if our share capital is divided into different classes of shares, the rights attached to any class (unless otherwise provided by the terms of issue of the shares of that class) may, whether or not the Company is being wound-up, be varied with the consent in writing of the holders of at least two-thirds of the issued shares of that class or with the sanction of a resolution passed by a majority of the votes cast at a separate general meeting of the holders of the shares of the class at which meeting the necessary quorum shall be two persons at least, in person or by proxy, holding or representing one-third of the issued shares of the class. The rights conferred upon the holders of the shares of any class issued with preferred or other rights shall not, unless otherwise expressly provided by the terms of issue of the shares of that class, be deemed to be varied by the creation or issue of further shares ranking pari passu therewith.

Our bye-laws give our board of directors the power to issue any unissued shares of the company on such terms and conditions as it may determine, subject to the terms of the bye-laws and any resolution of the shareholders to the contrary.

Common shares

Holders of our common shares are entitled to one vote per share on all matters submitted to a vote of holders of common shares. Under our bye-laws, each common share is entitled to dividends, if, as and when dividends are declared by our board of directors, subject to any preferred dividend right of the holders of any preference shares, if any. Holders of common shares have no pre-emptive, redemption, conversion or sinking fund rights. In the event of our liquidation, dissolution or winding up the holders of common shares are entitled to share equally and ratably in our assets, if any, remaining after the payment of all of our debts and liabilities, subject to any liquidation preference on any outstanding preference shares.

Board composition

Our bye-laws provide that the minimum number of directors shall be three or such other number as shall be determined from time to time by our board of directors. In addition, our bye-laws provide that our board of directors shall determine the maximum size of the board. As per the meeting of the board of directors of GeoPark Limited, which took place on May 10, 2022, the modification of the members of the board of directors was approved and it was determined that the maximum number of members will be nine. Therefore, the current number of members of the Board is nine.

Election and removal of directors

Our bye-laws provide that our directors shall hold office for such term as the shareholders shall determine or, in the absence of such determination, until the next annual general meeting or until their successors are elected or appointed or their office is otherwise vacated. Directors whose term has expired may offer themselves for re-election at each election of the directors.

A director may be removed by the shareholders at any special general meeting by a resolution adopted by 65% or more of the votes cast at the meeting, provided that notice of the shareholders meeting convened to remove the director is given to the director. The notice must contain a statement of the intention to remove the director and must be served on the director not less than fourteen days before the meeting. The director is entitled to attend the meeting and be heard on the motion for his removal.

In addition, our bye-laws provide that our board of directors may remove a director only for cause by the affirmative vote of at least three-quarters of the board of directors, provided that notice of any such meeting convened for the purpose of removing a director shall contain a statement of the intention to remove the director and must be served on the director not less than fourteen days before the meeting. The director is entitled to attend the meeting and be heard on the motion for his removal.

Any vacancy created by the removal of a director at a special general meeting may be filled at that meeting by the election of another director in his or her place or, in the absence of any such election, by the board of directors. Any other vacancy, including a newly created directorship due to an increase in the maximum number of directors on our board, may be filled by our board of directors.

Proceedings of board of directors

Our bye-laws provide that our business is to be managed and conducted by our board of directors. Our board of directors may act by the affirmative vote of a majority of the directors present at a meeting at which a quorum is present. The quorum necessary for the transaction of business at meetings of the board of directors shall be the presence of a majority of the board of directors from time to time. Our bye-laws also provide that resolutions unanimously signed by all directors are valid as if they had been passed at a meeting of the board duly called and constituted.

Duties of directors

The Companies Act authorizes the directors of a company, subject to its bye-laws, to exercise all powers of the company except those that are required by the Companies Act or the company's bye-laws to be exercised by the shareholders of the company. Our bye-laws provide that our business is to be managed and conducted by our board of directors. Under Bermuda common law, members of a board of directors owe a fiduciary duty to the Company to act in good faith in their dealings with or on behalf of the company, and to exercise their powers and fulfill the duties of their office honestly. This duty has the following essential elements: (1) a duty to act in good faith in the best interests of the company; (2) a duty not to make a personal profit from opportunities that arise from the office of director; (3) a duty to avoid conflicts of interest; and (4) a duty to exercise powers for the purpose for which such powers were intended. The Bermuda Companies Act also imposes a duty on directors (and officers) of a Bermuda company, to act honestly and in good faith, with a view to the best interests of the company, and to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. In addition, the Companies Act imposes various duties on directors (and officers) of a company with respect to certain matters of management and administration of the company. Under Bermuda law, directors (and officers) generally owe fiduciary duties to the company itself, not to the company's individual shareholders, creditors or any class thereof.

The Companies Act provides that in any proceedings for negligence, default, breach of duty or breach of trust against any director, if it appears to a court that such officer is or may be liable in respect of the negligence, default, breach of duty or breach of trust, but that he has acted honestly and reasonably, and that, having regard to all the circumstances of the case, including those connected with his appointment, he ought fairly to be excused for the negligence, default, breach of duty or breach of trust, that court may relieve him, either wholly or partly, from any liability on such terms as the court may think fit.

By comparison, under Delaware law, the business and affairs of a corporation are managed by or under the direction of its board of directors. In exercising their powers, directors are charged with a duty of care and a duty of loyalty. The duty of care requires that directors act in an informed and deliberate manner and to inform themselves, prior to making a business decision, of all relevant material information reasonably available to them. The duty of care also requires that directors exercise care in overseeing the conduct of corporate employees. The duty of loyalty is the duty to act in good faith, not out of self-interest, and in a manner which the director reasonably believes to be in the best interests of the shareholders. A party challenging the propriety of a decision of a board of directors bears the burden of rebutting the presumptions afforded to directors by the "business judgment rule." If the presumption is not rebutted, the business judgment rule attaches to protect the directors and their decisions. Where, however, the presumption is rebutted, the directors bear the burden of demonstrating the fairness of the relevant transaction. Notwithstanding the foregoing, Delaware courts subject directors' conduct to enhanced scrutiny in respect of defensive actions taken in response to a threat to corporate control and approval of a transaction resulting in a sale of control of the corporation.

Interested directors

Pursuant to our bye-laws, a director shall declare the nature of his interest in any contract or arrangement with the company as required by the Companies Act. A director so interested shall not, except in particular circumstances set out in our bye-laws, be entitled to vote or be counted in the quorum at a meeting in relation to any resolution in which he has an interest, which is to his knowledge, a material interest (otherwise than by virtue of his interest in shares or debentures or other securities of the company). A director will be liable to us for any secret profit realized from the transaction. In contrast, under Delaware law, such a contract or arrangement is voidable unless it is approved by a majority of disinterested directors or by a vote of shareholders, in each case if the material facts as to the interested director's relationship or interests are disclosed or are known to the disinterested directors or shareholders, or such contract or arrangement is fair to the corporation as of the time it is approved or ratified. Additionally, such interested director could be held liable for a transaction in which such director derived an improper personal benefit.

Indemnification of directors and officers

Section 98 of the Companies Act provides generally that a Bermuda company may indemnify its directors, officers and auditors against any liability which by virtue of any rule of law would otherwise be imposed on them in respect of any negligence, default, breach of duty or breach of trust, except in cases where such liability arises from fraud or dishonesty of which such director, officer or auditor may be guilty in relation to the company. Section 98 further provides that a Bermuda company may indemnify its directors, officers and auditors against any liability incurred by them in defending any proceedings, whether civil or criminal, in which judgment is awarded in their favour or in which they are acquitted or granted relief by the Supreme Court of Bermuda pursuant to section 281 of the Companies Act.

We have adopted provisions in our bye-laws that provide that we shall indemnify our officers and directors in respect of their actions and omissions, except in respect of their fraud or dishonesty, or to recover any gain, personal profit or advantage to which such director is not legally entitled. Our bye-laws provide that the shareholders waive all claims or rights of action that they might have, individually or in right of the company, against any of the company's directors for any act or failure to act in the performance of such director's duties, except in respect of any fraud or dishonesty of such director. Section 98A of the Companies Act permits us to purchase and maintain insurance for the benefit of any officer or director in respect of any loss or liability attaching to him in respect of any negligence, default, breach of duty or breach of trust, whether or not we may otherwise indemnify such officer or director. We have purchased and maintain a directors' and officers' liability policy for such a purpose.

Meetings of shareholders

Under Bermuda law, the company is required to convene at least one general meeting of shareholders each calendar year (the "annual general meeting"). However, the members may by resolution waive this requirement, either for a specific year or period of time, or indefinitely. When the requirement has been so waived, any member may, on notice to the company, terminate the waiver, in which case an annual general meeting must be called.

Bermuda law provides that a special general meeting of shareholders may be called by the board of directors of a company and must be called upon the request of shareholders holding not less than 10% of the paid-up capital of the company carrying the right to vote at general meetings. Bermuda law also requires that shareholders be given at least five days' advance notice of a general meeting, but the accidental omission to give notice to any person does not invalidate the proceedings at a meeting.

Our bye-laws provide that our board of directors may convene an annual general meeting or a special general meeting. Under our bye-laws, not less than fifteen nor more than sixty days' notice of an annual general meeting or a special general meeting must be given to each shareholder entitled to vote at such meeting. This notice requirement is subject to the ability to hold such meetings on shorter notice if such notice is agreed: (i) in the case of an annual general meeting by all of the shareholders entitled to attend and vote at such meeting; or (ii) in the case of a special general meeting by a majority in number of the shareholders entitled to attend and vote at the meeting holding not less than 95% in nominal value of the shares entitled to vote at such meeting. The quorum required for a general meeting of shareholders is two or more persons present in person and representing in person or by proxy in excess of 50% of the total issued voting shares in the Company throughout the meeting, provided that if the Company shall at any time have only one shareholder, one shareholder present in person or by proxy shall form the quorum. Unless otherwise required by law or by our bye-laws, shareholder action requires a resolution adopted by the affirmative votes of a majority of votes cast by shareholders at a general meeting at which a quorum is present.

Shareholder proposals

Under Bermuda law, shareholders holding at least 5% of the total voting rights of all the shareholders having at the date of the requisition a right to vote at the meeting to which the requisition relates or any group composed of at least 100 shareholders may require a proposal to be submitted to an annual general meeting of shareholders by giving a requisition in writing to the company. Under our bye-laws, any shareholders wishing to nominate a person for election as a director or propose business to be transacted at a meeting of shareholders must provide (among other things) advance notice, as set out in our bye-laws. Shareholders may only propose a person for election as a director at an annual general meeting.

Shareholder action by written consent

Our bye-laws provide that, except for the removal of auditors and directors, any actions which shareholders may take at a general meeting of shareholders may be taken by the shareholders through the unanimous written consent of all the shareholders who would be entitled to vote on the matter at the general meeting.

Amendment of memorandum of association and bye-laws

Our memorandum of association and bye-laws may be amended with the approval of a majority of our board of directors and by a resolution by a majority of the votes cast by shareholders who (being entitled to do so) vote in person or by proxy at any general meeting of the shareholders in accordance with the provisions of the bye-laws.

Under Bermuda law, the holders of an aggregate of not less than 20% in par value of the company's issued share capital or any class thereof have the right to apply to the Supreme Court of Bermuda for an annulment of any amendment of the memorandum of association adopted by shareholders at any general meeting, other than an amendment which alters or reduces a company's share capital as provided in the Companies Act. Where such an application is made, the amendment becomes effective only to the extent that it is confirmed by the Bermuda court. An application for an annulment of an amendment of the memorandum of association must be made within twenty-one days after the date on which the resolution altering the company's memorandum of association is passed and may be made on behalf of persons entitled to make the application by one or more of their number as they may appoint in writing for the purpose. No application may be made by shareholders voting in favour of the amendment.

Business combinations

The amalgamation or merger of a Bermuda company with another company or corporation (other than certain affiliated companies) requires the amalgamation or merger agreement to be approved by the company’s board of directors and by its shareholders. Under the Companies Act, unless the company’s bye-laws provide otherwise, the approval of 75% of the shareholders voting at a meeting is required to pass a resolution to approve the amalgamation or merger agreement, and the quorum for such meeting must be two persons holding or representing more than one-third of the issued shares of the company. Our bye-laws provide that an amalgamation or merger will require the approval of our board of directors and of our shareholders by a resolution adopted by 65% or more of the votes cast by shareholders who (being entitled to do so) vote in person or by proxy at any general meeting of the shareholders in accordance with the provisions of the bye-laws. Under Bermuda law, in the event of an amalgamation or merger of a Bermuda company with another company or corporation, a shareholder who did not vote in favor of the amalgamation or merger and who is not satisfied that fair value has been offered for such shareholder’s shares may, within one month of the notice of the shareholders meeting, apply to the Supreme Court of Bermuda to appraise the value of those shares.

Our bye-laws provide that the directors shall manage the business of the Company and may exercise all such powers as are not, by the Companies Act or by the bye-laws, required to be exercised by the Company in general meeting and may pay all expenses incurred in promoting and incorporating the company and may exercise all the powers of the Company including, but not by way of limitation, the power to borrow money and to mortgage or charge all or any part of the undertaking property and assets (present and future) and uncalled capital of the Company and to issue debentures and other securities, whether outright or as security for any debt, liability or obligation of the Company or any third party.

Compulsory Acquisition of Shares Held by Minority Holders

An acquiring party is generally able to acquire compulsorily the common shares of minority holders in the following ways:

(1) By a procedure under the Companies Act 1981 known as a “scheme of arrangement”. A scheme of arrangement could be effected by obtaining the agreement of the company and of holders of common shares, representing in the aggregate a majority in number and at least 75% in value of the common shareholders present and voting at a court ordered meeting held to consider the scheme of arrangement. The scheme of arrangement must then be sanctioned by the Bermuda Supreme Court. If a scheme of arrangement receives all necessary agreements and sanctions, upon the filing of the court order with the Registrar of Companies in Bermuda, all holders of common shares could be compelled to sell their shares under the terms of the scheme of arrangement.

(2) If the acquiring party is a company it may compulsorily acquire all the shares of the target company, by acquiring pursuant to a tender offer 90% of the shares or class of shares not already owned by, or by a nominee for, the acquiring party (the offeror), or any of its subsidiaries. If an offeror has, within four months after the making of an offer for all the

shares or class of shares not owned by, or by a nominee for, the offeror, or any of its subsidiaries, obtained the approval of the holders of 90% or more of all the shares to which the offer relates, the offeror may, at any time within two months beginning with the date on which the approval was obtained, require by notice any nontendering shareholder to transfer its shares on the same terms as the original offer. In those circumstances, nontendering shareholders will be compelled to sell their shares unless the Supreme Court of Bermuda (on application made within a one-month period from the date of the offeror's notice of its intention to acquire such shares) orders otherwise.

(3) Where one or more parties holds not less than 95% of the shares or a class of shares of a company, such holder(s) may, pursuant to a notice given to the remaining shareholders or class of shareholders, acquire the shares of such remaining shareholders or class of shareholders. When this notice is given, the acquiring party is entitled and bound to acquire the shares of the remaining shareholders on the terms set out in the notice, unless a remaining shareholder, within one month of receiving such notice, applies to the Supreme Court of Bermuda for an appraisal of the value of their shares. This provision only applies where the acquiring party offers the same terms to all holders of shares whose shares are being acquired.

Dividends and repurchase of shares

Pursuant to our bye-laws, our board of directors has the authority to declare dividends and authorize the repurchase of shares subject to applicable law. Under Bermuda law, a company may not declare or pay a dividend if there are reasonable grounds for believing that the company is, or would after the payment be, unable to pay its liabilities as they become due or the realizable value of its assets would thereby be less than its liabilities. Under Bermuda law, a company cannot purchase its own shares if there are reasonable grounds for believing that the company is, or after the repurchase would be, unable to pay its liabilities as they become due.

Shareholder suits

Class actions and derivative actions are generally not available to shareholders under Bermuda law. The Bermuda courts, however, would ordinarily be expected to permit a shareholder to commence an action in the name of a company to remedy a wrong to the company where the act complained of is alleged to be beyond the corporate power of the company or illegal, or would result in the violation of the company's memorandum of association or bye-laws. Furthermore, consideration would be given by a Bermuda court to acts that are alleged to constitute a fraud against the minority shareholders or, for instance, where an act requires the approval of a greater percentage of the company's shareholders than that which actually approved it.

When the affairs of a company are being conducted in a manner which is oppressive or prejudicial to the interests of some part of the shareholders, one or more shareholders may apply to the Supreme Court of Bermuda, which may make such order as it sees fit, including an order regulating the conduct of the company's affairs in the future or ordering the purchase of the shares of any shareholders by other shareholders or by the company.

Our bye-laws contain a provision by virtue of which our shareholders waive any claim or right of action that they may have, both individually and on our behalf, against any director in relation to any action or failure to take action by such director, including the breach of any fiduciary duty by a director, except in respect of any fraud or dishonesty of such director or to recover any gain, personal profit or advantage to which such director is not legally entitled.

Comparison of Bermuda law to Delaware corporate law

Bermuda law differs from the laws in effect in the United States and might afford less protection to shareholders.

Our shareholders could have more difficulty protecting their interests than would shareholders of a corporation incorporated in a jurisdiction of the United States. As a Bermuda company, we are governed by our memorandum of association and bye-laws and Bermuda company law. The provisions of the Companies Act, which applies to us, differs in some material respects from laws generally applicable to U.S. corporations and shareholders, including the provisions relating to interested directors, mergers and acquisitions, takeovers, shareholder lawsuits and indemnification of directors. Set forth below is a summary of these provisions, as well as modifications adopted pursuant to our bye-laws, which differ in certain respects from provisions of Delaware corporate law. Our shareholders approved the adoption of our bye-laws with effect on February 19, 2014, and amended with effect on July 15, 2021. Because the following statements are summaries, they do not discuss all aspects of Bermuda law that may be relevant to us and our shareholders.

Interested Directors. Under our bye-laws and the Companies Act, a director shall declare the nature of his interest in any contract or arrangement with the company. Our bye-laws further provide that a director so interested shall not, except in particular circumstances, be entitled to vote or be counted in the quorum at a meeting in relation to any resolution in which he has an interest, which is to his knowledge, a material interest (otherwise than by virtue of his interest in shares or debentures or other securities of the company). A director will be liable to us for any secret profit realized from the transaction. See “Item 10—B. Memorandum of association and bye-laws—Interested directors.”

Amalgamations, Mergers and Similar Arrangements. Pursuant to the Companies Act, the amalgamation or merger of a Bermuda company with another company or corporation (other than certain affiliates) requires the amalgamation or merger agreement to be approved by the company’s board of directors and by its shareholders. Under our bye-laws, an amalgamation or merger will require the approval of our board of directors and our shareholders by Special Resolution, which is a resolution adopted by 65% of more of the votes cast by shareholders who (being entitled to do so) vote in person or by proxy at any general meeting of the shareholders in accordance with the provisions of the bye-laws. The quorum for any such general meeting must be two or more persons, in person or by proxy, representing more than one-third of the issued shares of the company. Under Bermuda law, in the event of an amalgamation or merger of a Bermuda company with another company or corporation, a shareholder who did not vote in favor of the amalgamation or merger and who is not satisfied that fair value has been offered for such shareholders shares may, within one month of notice of the shareholders meeting, apply to the Supreme Court of Bermuda to appraise the fair value of those shares.

Under Delaware law, with certain exceptions, a merger, consolidation or sale of all or substantially all the assets of a corporation must be approved by the board of directors and a majority of the issued and outstanding shares entitled to vote thereon. Under Delaware law, a shareholder of a corporation participating in certain major corporate transactions may, under certain circumstances, be entitled to appraisal rights pursuant to which such shareholder may receive cash in the amount of the fair value of the shares held by such shareholder (as determined by a court) in lieu of the consideration such shareholder would otherwise receive in the transaction.

Shareholders’ Suit. Class actions and derivative actions are generally not available to shareholders under Bermuda law. The Bermuda courts, however, would ordinarily be expected to permit a shareholder to commence an action in the name of a company to remedy a wrong to the company where the act complained of is alleged to be beyond the corporate power of the company or illegal, or would result in the violation of the company’s memorandum of association or bye-laws. When the affairs of a company are being conducted in a manner which is oppressive or prejudicial to the interests of some part of the shareholders, one or more shareholders may apply to the Supreme Court of Bermuda, which may make such order as it sees fit, including an order regulating the conduct of the company’s affairs in the future or ordering the purchase of the shares of any shareholders by other shareholders or by the company. See “Item 10—B. Memorandum of association and bye-laws—Shareholder suits.”

Our bye-laws contain a provision by virtue of which our shareholders waive any claim or right of action that they might have, individually or in the right of the company, against any director for any act or failure to act in performance of such director’s duties, including the breach of any fiduciary duty, except in respect of any fraud or dishonesty of such director or to recover any gain, personal profit or advantage to which such director is not legally entitled. Class actions and derivative actions generally are available to shareholders under Delaware law for, among other things, breach of fiduciary duty, corporate waste and actions not taken in accordance with applicable law. In such actions, the court has discretion to permit the winning party to recover attorneys’ fees incurred in connection with such action.

Indemnification of Directors. We may indemnify our directors and officers in their capacity as directors or officers for any loss arising or liability attaching to them by virtue of any rule of law in respect of any negligence, default, breach of duty or breach of trust of which a director or officer may be guilty in relation to the company other than in respect of his own fraud or dishonesty. See “Item 10—B. Memorandum of association and bye-laws—Enforcement of Judgments.” Our bye-laws provide that we shall indemnify our officers and directors in respect of their acts and omissions, except in respect of their fraud or dishonesty, or to recover any gain, personal profit or advantage to which such Director is not legally entitled, and (by incorporation of the provisions of the Companies Act) that we may advance money to our officers and directors for the costs, charges and expenses incurred by our officers and directors in defending any civil or criminal proceedings against them on condition that the directors and officers repay the money if any allegations of fraud or dishonesty is proved against them provided, however, that, if the Companies Act requires, an advancement of expenses shall be made only upon delivery to the Company of an undertaking, by or on behalf of such indemnitee, to repay all amounts if it shall ultimately be determined by final judicial decision that such indemnitee is not entitled to be indemnified for such expenses under our bye-laws or otherwise. Under Delaware law, a corporation may indemnify a director or officer of the corporation against expenses (including attorneys' fees), judgments, fines and amounts paid in settlement actually and reasonably incurred in defense of an action, suit or proceeding by reason of such position if such director or officer acted in good faith and in a manner he or she reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, such director or officer had no reasonable cause to believe his or her conduct was unlawful. In addition, we have entered into customary indemnification agreements with our directors.

As a result of these differences, investors could have more difficulty protecting their interests than would shareholders of a corporation incorporated in the United States.

Tax matters. Under current Bermuda law, we are not subject to tax on income or capital gains in Bermuda. We have obtained an assurance from the Minister of Finance of Bermuda under the Exempted Undertakings Tax Protection Act 1966 that, in the event that any legislation is enacted in Bermuda imposing any tax computed on profits, income, any capital asset, gain or appreciation, or any tax in the nature of estate duty or inheritance, such tax shall not be applicable to us or to any of our operations or shares, debentures or other obligations, until March 31, 2035, except insofar as such tax applies to persons ordinarily resident in Bermuda or is payable by us in respect of real property owned or leased by us in Bermuda. We could be subject to taxes in Bermuda after that date. We are incorporated in Bermuda as an exempted company and pay annual Bermuda government fees. In addition, all entities employing individuals in Bermuda are required to pay a payroll tax and there are other sundry taxes payable, directly or indirectly, to the Bermuda government. Neither we nor our Bermuda subsidiaries employ individuals in Bermuda as at the date of this annual report.

Access to books and records and dissemination of information

Members of the general public have a right to inspect the public documents of a company available at the office of the Registrar of Companies in Bermuda. These documents include the company's memorandum of association, including its objects and powers, and certain alterations to the memorandum of association. The shareholders have the additional right to inspect the bye-laws of the company, minutes of general meetings and the company's audited financial statements, which must be presented to the annual general meeting. The register of members of a company is also open to inspection by shareholders and by members of the general public without charge. The register of members is required to be open for inspection for not less than two hours in any business day (subject to the ability of a company to close the register of members for not more than thirty days in a year). A company is required to maintain its share register in Bermuda but may, subject to the provisions of the Companies Act, establish a branch register outside of Bermuda. A company is required to keep at its registered office a register of directors and officers that is open for inspection for not less than two hours in any business day by members of the public without charge. A company is also required to file with the Registrar of Companies in Bermuda a list of its directors to be maintained on a register, which register will be available for public inspection subject to such conditions as the Registrar may impose and on payment of such fee as may be prescribed. Bermuda law does not, however, provide a general right for shareholders to inspect or obtain copies of any other corporate records.

Registrar or transfer agent

A register of holders of the common shares is maintained by Conyers Corporate Services (Bermuda) Limited in Bermuda, and a branch register is maintained in the United States by Computershare Trust Company, N.A., who serves as branch registrar and transfer agent.

Enforcement of Judgments

We are incorporated as an exempted company limited by shares under the laws of Bermuda, and substantially all of our assets are located in Colombia, Chile, Brazil, Argentina and Ecuador. In addition, most of our directors and executive officers reside outside the United States, and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors to effect service of process on those persons in the United States or to enforce in the United States judgments obtained in U.S. courts against us or those persons based on the civil liability provisions of the U.S. securities laws.

There is no treaty in force between the United States and Bermuda providing for the reciprocal recognition and enforcement of judgments in civil and commercial matters. However, the courts of Bermuda would recognize any final and conclusive monetary in personam judgement obtained in a U.S. court (other than a sum of money payable in respect of multiple damages, taxes or other charges of a like nature or in respect of a fine or other penalty) and would give a judgement based thereon provided that (i) the U.S. court that entered the judgment is recognized by the Bermuda court as having jurisdiction over us or our directors and officers, as determined by reference to Bermuda conflict of law rules, (ii) such court did not contravene the rules of natural justice of Bermuda, such judgment was not obtained by fraud, the enforcement of the judgment would not be contrary to the public policy of Bermuda, (iii) no new admissible evidence relevant to the action is submitted prior to the rendering of the judgment by the courts of Bermuda, and (iv) there is due compliance with the correct procedures under the laws of Bermuda.

An action brought pursuant to a public or penal law, the purpose of which is the enforcement of a sanction, power or right at the instance of the state in its sovereign capacity, may not be entertained by a Bermuda court. Certain remedies available under the laws of U.S. jurisdictions, including certain remedies under U.S. federal securities laws, may not be available under Bermuda law or enforceable in a Bermuda court, as they may be contrary to Bermuda public policy. Further, no claim may be brought in Bermuda against us or our directors and officers in the first instance for violations of U.S. federal securities laws because these laws have no extraterritorial jurisdiction under Bermuda law and do not have force of law in Bermuda. A Bermuda court may, however, impose civil liability on us or our directors and officers if the facts alleged in a complaint constitute or give rise to a cause of action under Bermuda law. However, section 281 of the Companies Act allows a Bermuda court, in certain circumstances, to relieve officers and directors of Bermuda companies of liability for acts of negligence, breach of duty or trust or other defaults.

No treaty exists between the United States and Chile for the reciprocal recognition and enforcement of foreign judgments. Chilean courts, however, have enforced valid and conclusive judgments for the payment of money rendered by competent U.S. courts by virtue of the legal principles of reciprocity and comity, subject to review in Chile of the U.S. judgment in order to ascertain whether certain basic principles of due process and public policy have been respected, without retrial or review of the merits of the subject matter. If a U.S. court grants a final judgment, enforceability of this judgment in Chile will be subject to obtaining the relevant exequatur (i.e., recognition and enforcement of the foreign judgment) according to Chilean civil procedure law in effect at that time, and depending on certain factors (the satisfaction or non-satisfaction of which would be determined by the Supreme Court of Chile). Currently, the most important of such factors are: the existence of reciprocity (if it can be proved that there is no reciprocity in the recognition and enforcement of the foreign judgment between the United States and Chile, that judgment would not be enforced in Chile); the absence of any conflict between the foreign judgment and Chilean laws (excluding for this purpose the laws of civil procedure) and Chilean public policy; the absence of a conflicting judgment by a Chilean court relating to the same parties and arising from the same facts and circumstances; the Chilean court's determination that the U.S. courts had jurisdiction, that process was appropriately served on the defendant and that the defendant was afforded a real opportunity to appear before the court and defend its case; and the judgment being final under the laws of the country in which it was rendered. Nonetheless, we have been advised by our Chilean counsel that there is doubt as to the enforceability in original actions in Chilean courts of liabilities predicated solely upon U.S. federal or state securities laws.

C. Material contracts

See "Item 4. Information on the Company—B. Business Overview—Significant Agreements."

D. Exchange controls

Not applicable.

E. Taxation

The following summary contains a description of certain Bermudian, U.S. federal income, Colombian and Chilean tax consequences of the acquisition, ownership and disposition of our common shares. The summary is based upon the tax laws of Bermuda, the United States, Colombia and Chile, and regulations thereunder as of the date hereof, which are subject to change.

Bermuda tax consideration

At the date of this annual report, there is no Bermuda income or profits tax, withholding tax, capital gains tax, capital transfer tax, estate duty or inheritance tax payable by us or by our shareholders in respect of our common shares. We have obtained an assurance from the Minister of Finance of Bermuda under the Exempted Undertakings Tax Protection Act 1966 that, in the event that any legislation is enacted in Bermuda imposing any tax computed on profits or income, or computed on any capital asset, gain or appreciation or any tax in the nature of estate duty or inheritance tax, such tax shall not, until March 31, 2035, be applicable to us or to any of our operations or to our common shares, debentures or other obligations except insofar as such tax applies to persons ordinarily resident in Bermuda or is payable by us in respect of real property owned or leased by us in Bermuda.

Material U.S. federal income tax considerations

The following is a description of the material U.S. federal income tax consequences to U.S. Holders (as defined below) of owning and disposing of our common shares. This discussion is not a comprehensive description of all tax considerations that may be relevant to a particular person's decision to hold our common shares. This discussion applies only to a U.S. Holder that holds our common shares as capital assets for tax purposes. In addition, it does not describe all of the tax consequences that may be relevant in light of the U.S. Holder's particular circumstances, including alternative minimum tax and Medicare contribution tax consequences and differing tax consequences applicable to a U.S. Holder subject to special rules, such as:

- certain financial institutions;
- a dealer or trader in securities who uses a mark-to-market method of tax accounting;
- a person holding common shares as part of a straddle, wash sale or conversion transaction or entering into a constructive sale with respect to the common shares;
- a person whose functional currency for U.S. federal income tax purposes is not the U.S. dollar;
- a partnership or other entities classified as partnerships for U.S. federal income tax purposes;
- a tax-exempt entity, including an "individual retirement account" or "Roth IRA;"
- a person that owns or is deemed to own 10% or more of our shares by vote or value;
- a person who acquired our shares pursuant to the exercise of an employee stock option or otherwise as compensation; or
- a person holding common shares in connection with a trade or business conducted outside of the United States.

If an entity that is classified as a partnership for U.S. federal income tax purposes holds common shares, the U.S. federal income tax treatment of a partner will generally depend on the status of the partner and the activities of the partnership. Partnerships holding common shares and partners in such partnerships should consult their tax advisers as to the particular U.S. federal income tax consequences of their investment in our common shares.

This discussion is based on the Internal Revenue Code of 1986, as amended (the "Code"), administrative pronouncements, judicial decisions, and final, temporary and proposed Treasury regulations, all as of the date hereof, any of which is subject to change, possibly with retroactive effect. U.S. Holders should consult their tax advisers concerning the U.S. federal, state, local and foreign tax consequences of owning and disposing of our common shares in their particular circumstances.

A "U.S. Holder" is a beneficial owner of our common shares for U.S. federal income tax purposes that is:

- a citizen or individual resident of the United States;
- a corporation, or other entity taxable as a corporation, created or organized in or under the laws of the United States, any state therein or the District of Columbia; or
- an estate or trust the income of which is subject to U.S. federal income taxation regardless of its source.

This discussion assumes that we are not, and will not become, a passive foreign investment company, as described below.

Taxation of distributions

Distributions paid on our common shares, other than certain *pro rata* distributions of common shares, will generally be treated as dividends to the extent paid out of our current or accumulated earnings and profits (as determined under U.S. federal income tax principles). Because we do not maintain calculations of our earnings and profits under U.S. federal income tax principles, it is expected that distributions will generally be reported to U.S. Holders as dividends. Subject to the passive foreign investment company rules described below, dividends paid by qualified foreign corporations to certain non-corporate U.S. Holders may be taxable at favorable rates. A foreign corporation is treated as a qualified foreign corporation with respect to dividends paid on stock that is readily tradable on an established securities market in the United States, such as the NYSE where our common shares are traded. Non-corporate U.S. Holders should consult their tax advisers to determine whether the favorable rate will apply to dividends they receive and whether they are subject to any special rules that limit their ability to be taxed at this favorable rate.

A dividend generally will be included in a U.S. Holder's income when received, will be treated as foreign-source income to U.S. Holders and will not be eligible for the dividends-received deduction generally available to U.S. corporations under the Code with respect to dividends paid by domestic corporations.

Sale or other taxable disposition of common shares

Gain or loss realized on the sale or other taxable disposition of our common shares will be capital gain or loss, and will be long-term capital gain or loss if the U.S. Holder held our common shares for more than one year. Long-term capital gain of a non-corporate U.S. Holder is generally taxed at preferential rates. The deductibility of capital losses is subject to limitations. The amount of the gain or loss will equal the difference between the U.S. Holder's tax basis in the common shares disposed of and the amount realized on the disposition. If a non-U.S. tax is withheld on the sale or disposition of common shares, a U.S. Holder's amount realized will include the gross amount of the proceeds of the sale or disposition before deduction of the non-U.S. tax. Gain or loss will generally be U.S.-source gain or loss for foreign tax credit purposes. U.S. Holders should consult their tax advisers as to whether the non-U.S. tax on gains may be creditable against the U.S. Holder's U.S. federal income tax on foreign-source income from other sources.

Recently issued Treasury regulations, which apply to foreign taxes paid or accrued in taxable years beginning on or after December 28, 2021, generally will preclude U.S. taxpayers from claiming a foreign tax credit with respect to any non-U.S. tax imposed on gains from disposition of our common shares, unless the tax is creditable under an applicable income tax treaty. With regards to the possible application of the Chilean or Colombian tax on transfers of shares, described under "—Chilean tax on transfers of shares" and "—Colombian tax on transfers of shares" below, respectively, the U.S. does not currently have an applicable income tax treaty with Chile or Colombia. Therefore, you generally will not be entitled to claim a foreign tax credit for any Chilean or Colombian taxes imposed on gains from taxable dispositions of our common shares (although it is possible that such taxes may reduce the amount realized on the disposition). The rules governing foreign tax credits are complex and, therefore, you should consult your own tax adviser regarding the creditability or deductibility of any Chilean or Colombian tax on disposition gains (including any applicable limitations) and the determination of the amount realized in your particular circumstances.

Passive foreign investment company rules

We believe that we were not a "passive foreign investment company," or PFIC, for U.S. federal income tax purposes for 2022, and we do not expect to be a PFIC in the foreseeable future. However, because the composition of our income and assets will vary over time, there can be no assurance that we will not be a PFIC for any taxable year. The determination of whether we are a PFIC is made annually and is based upon the composition of our income and assets (including the income and assets of, among others, entities in which we hold at least a 25% interest), and the nature of our activities.

If we were a PFIC for any taxable year during which a U.S. Holder held our common shares, gain recognized by a U.S. Holder on a sale or other disposition (including certain pledges) of our common shares would generally be allocated ratably over the U.S. Holder's holding period for the common shares. The amounts allocated to the taxable year of the sale or other disposition and to any year before we became a PFIC would be taxed as ordinary income. The amount allocated to each other taxable year would be subject to tax at the highest rate in effect for individuals or corporations for that year, as appropriate, and an interest charge would be imposed on the tax on such amount. Further, to the extent that any distribution received by a U.S. Holder on its common shares exceeds 125% of the average of the annual distributions on the shares received during the preceding three years or the U.S. Holder's holding period, whichever is shorter, that distribution would be subject to taxation in the same manner as gain, as described immediately above. Certain elections may be available that would result in alternative treatments (such as mark-to-market treatment) of our common shares. U.S. Holders should consult their tax advisers to determine whether any of these elections would be available and, if so, what the consequences of the alternative treatments would be in their particular circumstances.

Furthermore, if we were a PFIC or, with respect to a particular U.S. Holder, were treated as a PFIC for the taxable year in which we paid a dividend or the prior taxable year, the preferential dividend rates discussed above with respect to dividends paid to certain non-corporate U.S. Holders would not apply.

Information reporting and backup withholding

Payments of dividends and sales proceeds that are made within the United States or through certain U.S.-related financial intermediaries generally are subject to information reporting, and may be subject to backup withholding, unless (1) the U.S. Holder is a corporation or other exempt recipient or (2) in the case of backup withholding, the U.S. Holder provides a correct taxpayer identification number and certifies that it is not subject to backup withholding. The amount of any backup withholding from a payment to a U.S. Holder will be allowed as a credit against the U.S. Holder's U.S. federal income tax liability and may entitle it to a refund, provided that the required information is timely furnished to the Internal Revenue Service.

Chilean tax on transfers of shares

As provided in Decree Law No. 824 of 1974, income tax is triggered on the indirect transfer of shares, equity rights, interests or other rights in the equity, control or profits of a Chilean entity as well as transfers of other assets and property of permanent establishments or other businesses in Chile. Reforms introduced in 2014 imposed a measure which obliges the company from which shares are transferred to pay taxes if the entity which undertakes the transfer of shares fails to do so.

The indirect transfer rules apply to sales of shares of an entity:

- If such entity is an offshore holding company located in a black-listed tax haven jurisdiction as determined by Chilean tax law, or a black-listed jurisdiction, (such as Bermuda) that holds Chilean Assets; and either a Chilean resident holds 5% or more of such entity, or such entity's rights to equity, control or profits, or 50% or more of such entity's rights to equity or profits are held by residents in black-listed jurisdictions; or

- the shares or rights transferred represent 10% or more of the offshore holding company (considering dispositions by related persons and over the preceding 12-month period) and the underlying Chilean Assets indirectly transferred, in the proportion indirectly owned by the seller, (a) are valued in an amount equal to or higher than UTA 210,000 (approximately US$200 million) (adjusted by the Chilean inflation unit of reference) or (b) represent 20% or more of the market value of the interest held by such seller in such offshore holding company.

Based on information available to us, (i) no Chilean resident holds 5% or more of our rights to equity, control or profits; (ii) residents in black-listed jurisdictions do not hold 50% or more of our rights to equity, control or profits; (iii) the Chilean Assets are not valued at more than UTA 210,000; and (iv) the Chilean Assets do not represent 20% or more of the market value of the offshore holding companies. Therefore, we do not believe the indirect transfer rules will apply to transfers of our common shares, unless the shares or rights transferred represent 10% or more of the company and the other conditions described above are met (considering dispositions by related persons and over the preceding 12-month period).

However, there can be no assurance that, at any time in the future, a Chilean resident will not hold 5% or more of our rights to equity, control or profits or that residents in black-listed jurisdictions will not hold 50% or more of our rights to equity, control or profits. If this were to occur, all sales of our common shares would be subject to the indirect transfer tax referred to above.

Our expectations regarding the indirect transfer rules are based on our understandings, analysis and interpretation of these enacted indirect transfer rules, which are subject to additional interpretation and rule-making by the Chilean authorities. As such, there is uncertainty relating to the application by Chilean authorities of the indirect transfer rules on us.

Colombian tax on transfers of shares

In August 2020, the Colombian government enacted Decree 1103 that regulates the indirect transfer tax set in article 90-3 of the Colombian Tax Code. Through this regulation, the transfer of shares and assets of entities located abroad are taxed in Colombia when such transaction represents a transfer of underlying assets located in Colombia. The latter applies unless (i) shares transferred are listed on a stock exchange recognized by the Colombian Government and no more than 20% of such shares are owned by a single beneficiary; or (ii) the value of assets indirectly transferred represents less than 20% of book and/or fair market value of all assets owned by the non-resident entity transferor.

For income tax purposes, indirect transfer shall be assessed at fair market value of the Colombian underlying assets and the relevant tax basis is the one held in the underlying Colombian asset, which should be calculated based on the Colombian Tax Code rules. When the underlying assets are held by a Colombian branch, any taxable base determined shall be allocated first to amortization/depreciation recapture taxed as ordinary income.

When a subsequent indirect transfer is made, the tax basis of the underlying Colombian assets corresponds to the purchase price paid and allocated to the underlying Colombian assets. However, Decree 1103 clarifies that the tax basis of the entity owning the underlying asset in Colombia is not stepped up.

See "Item 3. Key Information—D. Risk Factors—Risks related to our common shares—The transfer of our common shares may be subject to capital gains taxes pursuant to indirect transfer rules in Colombia."

F. Dividends and paying agents

Not applicable.

G. Statement by experts

Not applicable.

H. Documents on display

We are subject to the informational requirements of the Exchange Act. Accordingly, we are required to file reports and other information with the SEC, including annual reports on Form 20-F and reports on Form 6-K. The SEC maintains an Internet website that contains reports and other information about issuers, like us, that file electronically with the SEC. The address of that website is www.sec.gov.

I. Subsidiary information

Not applicable.

ITEM 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to a variety of market risks, including commodity price risk, interest rate risk, currency risk and credit (counterparty and customer) risk. The term "market risk" refers to the risk of loss arising from adverse changes in interest rates, oil and natural gas prices and foreign currency exchange rates.

For further information on our market risks, please see Note 3 to our Consolidated Financial Statements.

ITEM 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

A. Debt securities

Not applicable.

B. Warrants and rights

Not applicable.

C. Other securities

Not applicable.

D. American Depositary Shares

Not applicable.

PART II

ITEM 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

A. Defaults

No matters to report.

B. Arrears and delinquencies

No matters to report.

ITEM 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

Not applicable.

ITEM 15. CONTROLS AND PROCEDURES

A. Disclosure Controls and Procedures

As of December 31, 2022, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act). There are inherent limitations to the effectiveness of any disclosure controls and procedures system, including the possibility of human error and circumventing or overriding them. Even if effective, disclosure controls and procedures can provide only reasonable assurance of achieving their control objectives.

Based on such evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to provide reasonable assurance that the information we are required to disclose in the reports we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and (2) accumulated and communicated to our management to allow timely decisions regarding required disclosures.

B. Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining an adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act.

Our internal control over financial reporting is a process designed by, or under the supervision of, our principal executive and principal financial officers, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes, in accordance with generally accepted accounting principles. These include those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of our assets;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements, in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorization of our management and directors; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, effective control over financial reporting cannot, and does not, provide absolute assurance of achieving our control objectives. Also, projections of, and any evaluation of effectiveness of the internal controls in future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our Chief Executive Officer, our Chief Financial Officer, and our Director of Legal and Governance, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2022, based on the criteria established in Internal Control - Integrated Framework of the Committee of Sponsoring Organizations of the Treadway Commission (2013).

Based on this assessment, management believes that, as of December 31, 2022, its internal control over financial reporting was effective based on those criteria.

C. Attestation Report of the Registered Public Accounting Firm

The effectiveness of the Company's internal control over financial reporting as of December 31, 2022, has been audited by Pistrelli, Henry Martin y Asociados S.R.L. (member of Ernst & Young Global Limited), an independent registered public accounting firm, as stated in their report which is included on page F-4 to F-5 of this annual report.

D. Changes in Internal Control over Financial Reporting

There have been no changes in the Company's internal control over financial reporting that occurred during the year ended December 31, 2022, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

ITEM 16. RESERVED

ITEM 16A. Audit committee financial expert

We have determined that Mr. Robert Bedingfield, Mr. Constantin Papadimitriou and Mr. Carlos E. Macellari are independent, as such term is defined under SEC rules applicable to foreign private issuers. In addition, Mr. Robert Bedingfield is regarded as audit committee financial expert.

ITEM 16B. Code of Conduct

We have adopted a code of conduct applicable to the board of directors and all employees. Since its effective date on September 24, 2012, we have not waived compliance with or amended the code of conduct.

ITEM 16C. Principal Accountant Fees and Services

The independent registered public accounting firm for the fiscal year ended December 31, 2022 and 2021 was Pistrelli, Henry Martin y Asociados S.R.L. (member of Ernst & Young Global Limited).

The following table provides detail in respect of audit, audit related, tax and other fees billed by the independent registered public accounting firm and other member firms of Ernst & Young Global Limited for professional services:

	2022	2021
	(in millions of US$)	
Audit fees	0.88	1.02
Audit related fees	0.09	0.07
Tax services fees	0.03	0.05
Total	**1.00**	**1.14**

Fees are shown net of VAT and other associated tax charges.

Audit Fees

Audit fees are fees billed for professional services rendered by the principal accountant for the audit of the registrant's annual financial statements or services that are normally provided by the accountant in connection with statutory and regulatory filings or engagements for those fiscal years. It includes the audit of our Consolidated Financial Statements and other services that generally only the independent accountant reasonably can provide, such as statutory audits.

Audit-Related Fees

Audit-related fees are fees billed for assurance and related services that are reasonably related to the performance of the audit or review of our Consolidated Financial Statements and not reported under the previous category. These services would include, among others: comfort letters, consents and assistance with and review of documents, accounting consultations and audits in connection with acquisitions, attestation of services that are not required by statue or regulation and consultation concerning financial accounting and reporting standards.

Tax Fees

Tax fees are fees billed for professional services for tax compliance, tax advice and tax planning.

Pre-Approval Policies and Procedures

Following the listing of our common shares on the NYSE, the Audit Committee proposes the appointment of the independent auditor to the board of directors to be put to shareholders for approval at the Annual General meeting. The Audit Committee oversees the auditor selection process for new auditors and ensures key partners in the appointed firm are rotated in accordance with best practices. Also, following our NYSE listing, the Audit Committee is required to pre-approve the audit and non-audit fees and services performed by the Company's auditors in order to be sure that the provision of such services does not impair the audit firm's independence.

All of the audit fees, audit-related fees and tax fees described in this item 16C have been approved by the Audit Committee.

ITEM 16D. Exemptions from the listing standards for audit committees

None.

ITEM 16E. Purchases of equity securities by the issuer and affiliated purchasers.

The following table presents purchases of our common shares by the company and "affiliated purchasers" (as that term is defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934, as amended) during 2022:

2022	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet be Purchased Under the Plans or Programs
January 5 to January 31, 2022	121,836	12.80	121,836	5,582,626 shares
February 1 to February 23, 2022	80,000	14.45	80,000	5,502,626 shares
March 15, 2022	30,000	13.45	30,000	5,472,626 shares
May 12 to May 27, 2022	63,538	14.85	63,538	5,409,088 shares
June 10 to June 30, 2022	396,000	13.65	396,000	5,013,088 shares
July 1 to July 26, 2022	434,566	11.61	434,566	4,578,522 shares
August 2 to August 30, 2022	322,000	12.84	322,000	4,256,522 shares
September 1 to September 29, 2022	353,795	12.40	353,795	3,902,727 shares
October 11 to October 24, 2022	138,061	13.96	138,061	3,764,666 shares
November 15 to November 30, 2022	192,386	14.24	192,386	5,661,899 shares
December 1 to December 30, 2022	611,540	13.93	611,540	5,050,359 shares

On November 4, 2020, our board of directors approved a new program to repurchase up to 10% of our shares outstanding or approximately 6,062,000 shares. The repurchase program begun on November 5, 2020, and was set to expire on November 15, 2021. On November 10, 2021, our board of directors approved the renewal of the program to repurchase up to 10% of our shares outstanding or approximately 6,074,000 shares. The repurchase program begun on November 10, 2021, and was set to expire on November 10, 2022. Finally, on November 9, 2022, our board of directors approved a new renewal of the program to repurchase up to 10% of our shares outstanding or approximately 5,854,285 shares until December 31, 2023.

ITEM 16F. Change in registrant's certifying accountant

Not applicable.

ITEM 16G. Corporate governance

Our common shares are listed on the NYSE. We are therefore required to comply with certain of the NYSE's corporate governance listing standards (the "NYSE Standards"). As a foreign private issuer, we may follow our home country's corporate governance practices in lieu of most of the NYSE Standards. Our corporate governance practices differ in certain significant respects from those that U.S. companies must adopt in order to maintain NYSE listing and, in accordance with Section 303A.11 of the NYSE Listed Company Manual, a brief, general summary of those differences is provided as follows.

Director independence

The NYSE Standards require a majority of the membership of NYSE-listed company boards to be composed of independent directors. Neither Bermuda law, the law of our country of incorporation, nor our memorandum of association or bye-laws require a majority of our board to consist of independent directors.

At the date of this annual report, 67% of our board of directors is independent.

Non-management directors' executive sessions

The NYSE Standards require non-management directors of NYSE-listed companies to meet at regularly scheduled executive sessions without management. Our memorandum of association and bye-laws do not require our non-management directors to hold such meetings.

Committee member composition

The NYSE Standards require domestic NYSE-listed domestic companies to have a nominating/corporate governance committee and a compensation committee that are composed entirely of independent directors. Bermuda law, the law of our country of incorporation, does not impose similar requirements.

Independence of the compensation committee and its advisers

On January 11, 2013, the SEC approved NYSE listing standards that require that the board of directors of a domestic listed company consider two factors (in addition to the existing general independence tests) in the evaluation of the independence of compensation committee members: (i) the source of compensation of the director, including any consulting, advisory or other compensatory fees paid by the listed company, and (ii) whether the director has an affiliate relationship with the listed company, a subsidiary of the listed company or an affiliate of a subsidiary of the listed company. In addition, before selecting or receiving advice from a compensation consultant or other adviser, the compensation committee of a listed company will be required to take into consideration six specific factors, as well as all other factors relevant to an adviser's independence.

Foreign private issuers, such as us, will be exempt from these requirements if home country practice is followed. Bermuda law does not impose similar requirements, so we will not be required to implement the NYSE listing standards relating to compensation committees of domestic listed companies. All of the members of our compensation committee are independent, and the charter of our compensation committee does not require the compensation committee to consider the independence of any advisers that assist them in fulfilling their duties.

Additional audit committee functions

The NYSE standards require that audit committees of domestic companies to serve a number of functions in addition to reviewing and approving the company's financial statements, engaging auditors and assessing their independence, and obtaining the legal and other professional advice of experts when necessary. For instance, the NYSE Standards require that the audit committee meet independently with management in a separate session in order to maximize the effectiveness of the committee's oversight function. In addition, audit committees must obtain and review a report by the independent auditors describing the firm's internal quality-control procedures and any issues raised by these procedures. Finally, audit committees are responsible for designing and implementing an internal audit function that assesses the company's risk management processes and systems of internal control on an ongoing basis.

Foreign private issuers such as us are exempt from these additional requirements if home country practice is followed. Bermuda law does not impose similar requirements, and consequently, our audit committee does not perform these additional functions. Our Audit Committee is composed exclusively of independent members.

Miscellaneous

In addition to the above differences, we are not required to: make our audit and compensation committees prepare a written charter that addresses either purposes and responsibilities or performance evaluations in a manner that would satisfy the NYSE's requirements; acquire shareholder approval of equity compensation plans in certain cases; or adopt and make publicly available corporate governance guidelines.

We are incorporated under, and are governed by, the laws of Bermuda. For a summary of some of the differences between provisions of Bermuda law applicable to us and the laws applicable to companies incorporated in Delaware and their shareholders, See "Item 10. Additional Information—B. Memorandum of association and bye-laws."

ITEM 16H. Mine safety disclosure

Not applicable.

ITEM 16I. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

ITEM 17. Financial statements

We have responded to Item 18 in lieu of this item.

ITEM 18. Financial statements

Financial Statements are filed as part of this annual report, see pages F-1 to F-77 to this annual report.

ITEM 19. Exhibits

Exhibit no.	Description
1.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
1.2	Memorandum of Association (incorporated herein by reference to Exhibit 3.2 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
1.3	Current bye-laws (incorporated herein by reference to Exhibit 1.3 to the Company's Annual Report on Form 20-F filed with the SEC on March 31, 2021).
1.4	Certificate of Incorporation on Name Change (incorporated herein by reference to Exhibit 1.4 to the Company's Annual Report on Form 20-F filed with the SEC on March 31, 2021).
2.1	Indenture dated January 17, 2020, among GeoPark Limited and the Bank of New York Mellon (incorporated herein by reference to Exhibit 2.3 to the Company's Annual Report on Form 20-F filed with the SEC on April 1, 2020)
2.2	First Supplemental Indenture dated August 25, 2021, among GeoPark Limited and GeoPark Colombia S.A.S. and the Bank of New York Mellon (incorporated herein by reference to Exhibit 2.6 to the Company's Annual Report on Form 20-F filed with the SEC on March 31, 2022).
2.3	Second Supplemental Indenture dated June 27, 2022, among GeoPark Limited and the Bank of New York Mellon. *
2.4	Description of Securities. *
4.1	Special Contract for the Exploration and Exploitation of Hydrocarbons, Fell Block, dated April 29, 1997, among the Republic of Chile, the Chilean Empresa Nacional de Petróleo (ENAP) and Cordex Petroleums Inc. (incorporated herein by reference to Exhibit 10.1 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.2	Exploration and Production Contract regarding exploration for and exploitation of hydrocarbons in the Llanos 34 Block, dated March 13, 2009, between the Colombian Agencia Nacional de Hidrocarburos and Unión Temporal Llanos 34 (incorporated herein by reference to Exhibit 10.3 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.3	Contract for the sale and Purchase of Natural Gas 2017-2027 between GeoPark Fell SpA and Methanex Chile SpA dated March 31, 2017 (incorporated herein by reference to Exhibit 4.22 to the Company's Annual Report on Form 20-F filed with the SEC on April 11, 2017).
4.4	Purchase and Sale Agreement for Crude Oil and Condensate of Fell Block between Empresa Nacional del Petróleo (ENAP) and GeoPark Fell S.p.A., dated April 21, 2017 (incorporated herein by reference to Exhibit 4.24 to the Company's Annual Report on Form 20-F filed with the SEC on April 12, 2018).
8.1	Subsidiaries of GeoPark Limited.*
12.1	Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002.*
12.2	Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002.*
13.1	Certification pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.*
13.2	Certification pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.*
15.1	Consent of Pistrelli, Henry Martin y Asociados (member of Ernst & Young Global Limited). *
15.2	Consents of DeGolyer and MacNaughton to use its report.*

Exhibit no.	Description
99.1	Reserves Report of DeGolyer and MacNaughton dated February 23, 2023, for reserves in Brazil, Chile, Colombia and Ecuador as of December 31, 2022.*
101.INS	Inline XBRL Instance Document*
101.SCH	XBRL Taxonomy Extension Schema Document*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document*
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document*
101.LAB	XBRL Taxonomy Extension Label Linkbase Document*
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document*
104	104 Cover Page Interactive Data File (formatted in Inline XBRL and included in Exhibit 101)

* Filed with this Annual Report on Form 20-F.

SIGNATURES

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

GEOPARK LIMITED

By: /s/ Andrés Ocampo
Name: Andrés Ocampo
Title: Chief Executive Officer and Director

Date: March 30, 2023

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the board of directors of
GeoPark Limited

Opinion on the Financial Statements

We have audited the accompanying consolidated statements of financial position of GeoPark Limited (the Company) as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, changes in equity and cash flow for each of the three years in the period ended December 31, 2022 and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 8, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (i) relates to accounts or disclosures that are material to the financial statements and (ii) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Effect of estimated proved and probable oil and gas reserves on the depreciation of property, plant and equipment

Description of the Matter

At December 31, 2022, the carrying value of the Company's property, plant and equipment was US$ 667 million and depreciation expense was US$ 91 million for the year then ended. As discussed in Note 2.11 the proved and probable reserves are used by the Company in the successful efforts method of accounting for its oil and gas properties. Under such method oil and gas properties are depreciated using the unit-of-production method based on commercial proved and probable oil and gas reserves, as estimated by an independent international oil and gas consulting firm. Proved and probable oil and gas reserves estimates are based on geological, geophysical and engineering assessments of expected reservoir characteristics, future production rates based on historical performance and expected future operating and investment activities. Estimating reserves also requires the selection of inputs, including future oil and gas prices and quality differentials, assumed effects of regulation by governmental agencies, tax rates by jurisdiction and future development and operating costs, among others.

Auditing the Company's depreciation calculations is complex because of the use of the work of the independent international oil and gas consulting firm and the evaluation of management's determination of the inputs described above used by the engineers in estimating commercial proved and probable oil and gas reserves. Also, the assumptions used by management are subject to changes due to future events and conditions and evaluating them requires significant auditor judgement.

How We Addressed the Matter in Our Audit

We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's internal controls over its process to calculate depreciation expense, including management's controls over proved and probable oil and gas reserves' estimation process.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's internal reservoir engineers primarily responsible for overseeing the preparation of the reserve estimates and the independent international oil and gas consulting firm hired by the Company. In addition, we evaluated the completeness and accuracy of the financial data and inputs used in estimating proved and probable oil and gas reserves and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan by assessing consistency of the development projections with the Company's drill plan and the availability of capital to develop such plan. We also tested the mathematical accuracy of the depreciation computations of property, plant and equipment, including comparing the proved and probable oil and gas reserve amounts used in the calculations to the Reserve Reports prepared by the independent international oil and gas consulting firm.

/s/ PISTRELLI, HENRY MARTIN Y ASOCIADOS S.R.L.
Member of Ernst & Young Global Limited

We have served as the Company's auditor since 2020.
Buenos Aires, Argentina
March 8, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the board of directors of
GeoPark Limited

Opinion on Internal Control over Financial Reporting

We have audited GeoPark Limited's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 Framework) ("the COSO criteria"). In our opinion, GeoPark Limited (the Company) maintained, in all material respects, effective internal control over financial reporting at December 31, 2022, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated statements of financial position of the Company as of December 31, 2022 and 2021, the related consolidated statements of income, comprehensive income, changes in equity and cash flow for each of the three years in the period ended December 31, 2022 and the related notes, and our report dated March 8, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PISTRELLI, HENRY MARTIN Y ASOCIADOS S.R.L.
Member of Ernst & Young Global Limited

Buenos Aires, Argentina
March 8, 2023

CONSOLIDATED STATEMENT OF INCOME

Amounts in US$´000	Note	2022	2021	2020
REVENUE	**7**	**1,049,579**	**688,543**	**393,692**
Commodity risk management contracts (loss) gain	8	(70,221)	(109,191)	8,081
Production and operating costs	9	(359,779)	(212,790)	(125,072)
Geological and geophysical expenses	12	(10,529)	(7,891)	(14,951)
Administrative expenses	13	(50,024)	(46,828)	(50,315)
Selling expenses	14	(7,995)	(8,730)	(5,844)
Depreciation		(96,692)	(88,969)	(118,073)
Write-off of unsuccessful exploration efforts	20	(25,789)	(12,262)	(52,652)
Impairment loss for non-financial assets, net	20-37	—	(4,334)	(133,864)
Other income (expenses)		527	(11,739)	(11,665)
OPERATING PROFIT (LOSS)		**429,077**	**185,809**	**(110,663)**
Financial expenses	15	(57,073)	(64,112)	(64,582)
Financial income	15	3,180	1,652	3,166
Foreign exchange gain (loss)	15	19,725	5,049	(13,008)
PROFIT (LOSS) BEFORE INCOME TAX		**394,909**	**128,398**	**(185,087)**
Income tax expense	17	(170,474)	(67,271)	(47,863)
PROFIT (LOSS) FOR THE YEAR		**224,435**	**61,127**	**(232,950)**
Earnings (Losses) per share (in US$). Basic	19	**3.78**	**1.00**	**(3.84)**
Earnings (Losses) per share (in US$). Diluted	19	**3.75**	**0.99**	**(3.84)**

The notes on pages F-11 to F-77 are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Amounts in US$´000	2022	2021	2020
Profit (Loss) for the year	224,435	61,127	(232,950)
Other comprehensive income:			
Items that may be subsequently reclassified to profit or loss			
Currency translation differences	2,121	(1,438)	(8,449)
Gain (Loss) on cash flow hedges	966	—	(6,770)
Income tax (expense) benefit relating to cash flow hedges	(483)	—	2,166
Other comprehensive profit (loss) for the year	**2,604**	**(1,438)**	**(13,053)**
Total comprehensive profit (loss) for the year	**227,039**	**59,689**	**(246,003)**

The notes on pages F-11 to F-77 are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

Amounts in US$´000	Note	2022	2021
ASSETS			
NON-CURRENT ASSETS			
Property, plant and equipment	20	666,879	614,047
Right-of-use assets	28	37,011	21,014
Prepayments and other receivables	22	121	148
Other financial assets	25	12,877	13,883
Deferred income tax asset	18	18,943	14,072
TOTAL NON-CURRENT ASSETS		**735,831**	**663,164**
CURRENT ASSETS			
Inventories	23	14,434	10,915
Trade receivables	24	71,794	70,531
Prepayments and other receivables	22	22,106	22,650
Derivative financial instrument assets	25	967	126
Other financial assets	25	—	864
Cash and cash equivalents	25	128,843	100,604
Assets held for sale	36	—	26,887
TOTAL CURRENT ASSETS		**238,144**	**232,577**
TOTAL ASSETS		**973,975**	**895,741**
EQUITY			
Equity attributable to owners of the Company			
Share capital	26.1	58	60
Share premium		134,798	169,220
Reserves		61,876	83,554
Accumulated losses		(81,147)	(314,779)
TOTAL EQUITY		**115,585**	**(61,945)**
LIABILITIES			
NON-CURRENT LIABILITIES			
Borrowings	27	485,114	656,176
Lease liabilities	28	22,051	12,513
Provisions and other long-term liabilities	29	51,947	62,848
Deferred income tax liability	18	70,123	20,947
Trade and other payables	30	—	1,540
TOTAL NON-CURRENT LIABILITIES		**629,235**	**754,024**
CURRENT LIABILITIES			
Borrowings	27	12,528	17,916
Lease liabilities	28	10,000	8,231
Derivative financial instrument liabilities	25	19	20,757
Current income tax liabilities		65,002	8,801
Trade and other payables	30	141,606	127,513
Liabilities associated with assets held for sale	36	—	20,444
TOTAL CURRENT LIABILITIES		**229,155**	**203,662**
TOTAL LIABILITIES		**858,390**	**957,686**
TOTAL EQUITY AND LIABILITIES		**973,975**	**895,741**

The notes on pages F-11 to F-77 are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

Amount in US$'000	Share Capital	Share Premium	Other Reserve	Translation Reserve	Accumulated Losses	Total
	Attributable to owners of the Company					
Equity as of January 1, 2020	**59**	**173,716**	**116,291**	**(3,820)**	**(153,361)**	**132,885**
Comprehensive income:						
Loss for the year	—	—	—	—	(232,950)	(232,950)
Other comprehensive loss for the year	—	—	(4,604)	(8,449)	—	(13,053)
Total Comprehensive loss for the year 2020	**—**	**—**	**(4,604)**	**(8,449)**	**(232,950)**	**(246,003)**
Transactions with owners:						
Share-based payment [a] (Note 31)	2	7,349	—	—	5,445	12,796
Repurchase of shares (Note 26.1)	(1)	(4,008)	—	—	—	(4,009)
Cash distribution (Note 26.2)	—	—	(4,859)	—	—	(4,859)
Stock distribution (Note 26.3)	1	2,342	(2,343)	—	—	—
Total 2020	**2**	**5,683**	**(7,202)**	**—**	**5,445**	**3,928**
Balances as of December 31, 2020	**61**	**179,399**	**104,485**	**(12,269)**	**(380,866)**	**(109,190)**
Comprehensive income:						
Profit for the year	—	—	—	—	61,127	61,127
Other comprehensive loss for the year	—	—	—	(1,438)	—	(1,438)
Total Comprehensive (loss) profit for the year 2021	**—**	**—**	**—**	**(1,438)**	**61,127**	**59,689**
Transactions with owners:						
Share-based payment (Note 31)	—	1,661	—	—	4,960	6,621
Repurchase of shares (Note 26.1)	(1)	(11,840)	—	—	—	(11,841)
Cash distribution (Note 26.2)	—	—	(7,224)	—	—	(7,224)
Total 2021	**(1)**	**(10,179)**	**(7,224)**	**—**	**4,960**	**(12,444)**
Balances as of December 31, 2021	**60**	**169,220**	**97,261**	**(13,707)**	**(314,779)**	**(61,945)**
Comprehensive income:						
Profit for the year	—	—	—	—	224,435	224,435
Other comprehensive profit for the year	—	—	483	2,121	—	2,604
Total Comprehensive profit for the year 2022	**—**	**—**	**483**	**2,121**	**224,435**	**227,039**
Transactions with owners:						
Share-based payment (Note 31)	1	1,840	—	—	9,197	11,038
Repurchase of shares (Note 26.1)	(3)	(36,262)	—	—	—	(36,265)
Cash distribution (Note 26.2)	—	—	(24,282)	—	—	(24,282)
Total 2022	**(2)**	**(34,422)**	**(24,282)**	**—**	**9,197**	**(49,509)**
Balances as of December 31, 2022	**58**	**134,798**	**73,462**	**(11,586)**	**(81,147)**	**115,585**

(a) Includes issuance of shares to certain employees as part of their 2019 bonus compensation of US$ 4,352,000.

The notes on pages F-11 to F-77 are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOW

Amounts in US$'000	Note	2022	2021	2020
Cash flows from operating activities				
Profit (Loss) for the year		224,435	61,127	(232,950)
Adjustments for:				
Income tax expense	17	170,474	67,271	47,863
Depreciation		96,692	88,969	118,073
Loss on disposal of property, plant and equipment		73	787	417
Impairment loss for non-financial assets	20-37	—	4,334	133,864
Write-off of unsuccessful exploration efforts	20	25,789	12,262	52,652
Accrual of borrowing's interests		36,360	44,378	48,690
Borrowings cancellation costs	15	5,141	6,308	—
Amortization of other long-term liabilities	29	(2,407)	(223)	(387)
Unwinding of long-term liabilities	15	6,026	5,079	5,894
Accrual of share-based payment		11,038	6,621	8,444
Foreign exchange (gain) loss	15	(19,725)	(5,049)	3,594
Unrealized (gain) loss on commodity risk management contracts	8	(13,023)	(463)	12,978
Income tax paid		(33,355)	(65,273)	(25,193)
Changes in working capital	5	(40,047)	(9,351)	(5,240)
Cash flows from operating activities – net		**467,471**	**216,777**	**168,699**
Cash flows from investing activities				
Purchase of property, plant and equipment		(168,808)	(129,258)	(75,298)
Acquisition of business, net of cash acquired	36.1	—	—	(272,335)
Proceeds from disposal of long-term assets	36.2-36.3	15,135	2,700	—
Cash flows used in investing activities – net		**(153,673)**	**(126,558)**	**(347,633)**
Cash flows from financing activities				
Proceeds from borrowings	5	—	172,174	350,000
Debt issuance costs paid	5	—	(2,019)	(7,507)
Principal paid	5	(172,522)	(274,934)	(3,575)
Interest paid	5	(36,514)	(42,592)	(37,594)
Borrowings cancellation and other costs paid	5	(9,118)	(12,908)	—
Lease payments	5	(7,851)	(7,518)	(9,380)
Repurchase of shares	26.1	(36,265)	(11,841)	(4,009)
Cash distribution	26.2	(24,282)	(7,224)	(4,859)
Payments for transactions with former non-controlling interest		—	(3,580)	(11,931)
Cash flows (used in) from financing activities – net		**(286,552)**	**(190,442)**	**271,145**
Net increase (decrease) in cash and cash equivalents		**27,246**	**(100,223)**	**92,211**
Cash and cash equivalents at January 1		100,604	201,907	111,180
Currency translation differences		993	(1,080)	(1,484)
Cash and cash equivalents at the end of the year		**128,843**	**100,604**	**201,907**
Ending Cash and cash equivalents are specified as follows:				
Cash in bank and bank deposits		128,831	100,587	201,884
Cash in hand		12	17	23
Cash and cash equivalents		**128,843**	**100,604**	**201,907**

The notes on pages F-11 to F-77 are an integral part of these Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 General Information

GeoPark Limited (the "Company") is a company incorporated under the law of Bermuda. The Registered Office address is Clarendon House, 2 Church Street, Hamilton HM11, Bermuda.

The principal activities of the Company and its subsidiaries (the "Group" or "GeoPark") are exploration, development and production for oil and gas reserves in Colombia, Chile, Brazil and Ecuador.

These Consolidated Financial Statements were authorized for issue by the board of directors on March 7, 2023 and have been approved to be included in our 2022 annual report (Form 20-F) on March 30, 2023.

Note 2 Summary of significant accounting policies

The principal accounting policies applied in the preparation of these Consolidated Financial Statements are set out below. These policies have been consistently applied to the years presented, unless otherwise stated.

2.1 Basis of preparation

The Consolidated Financial Statements of GeoPark Limited have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), under the historical cost basis, except for the following: certain financial assets and liabilities (including derivative instruments) measured at fair value, and assets held for sale – measured at fair value less costs to sell.

The Consolidated Financial Statements are presented in thousands of United States Dollars (US$'000) and all values are rounded to the nearest thousand (US$'000), except in the footnotes and where otherwise indicated.

The preparation of financial statements in conformity with IFRS requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Group's accounting policies. The areas involving a higher degree of judgement or complexity, or areas where assumptions and estimates are significant to the Consolidated Financial Statements are disclosed in this note under the title "Accounting estimates and assumptions".

All the information included in these Consolidated Financial Statements corresponds to the Group, except where otherwise indicated.

2.1.1 Changes in accounting policy and disclosure

2.1.1.1 New and amended standards and interpretations

The Group applied for the first-time certain standards and amendments, which are effective for annual periods beginning on or after January 1, 2022. The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective.

<u>Onerous Contracts – Costs of Fulfilling a Contract – Amendments to IAS 37</u>

An onerous contract is a contract under which the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received under it.

The amendments specify that when assessing whether a contract is onerous or loss-making, an entity needs to include costs that relate directly to a contract to provide goods or services including both incremental costs and an allocation of costs directly related to contract activities. General and administrative costs do not relate directly to a contract and are excluded unless they are explicitly chargeable to the counterparty under the contract.

The Group applied the amendments at the beginning of the reporting period. These amendments had no impact on the Consolidated Financial Statements of the Group as there were no contracts for which it had not fulfilled all of its obligations during the reporting period.

Reference to the Conceptual Framework – Amendments to IFRS 3

The amendments replace a reference to a previous version of the IASB's Conceptual Framework with a reference to the current version issued in March 2018 without significantly changing its requirements.

The amendments add an exception to the recognition principle of IFRS 3 Business Combinations to avoid the issue of potential 'day 2' gains or losses arising for liabilities and contingent liabilities that would be within the scope of IAS 37 Provisions, Contingent Liabilities and Contingent Assets or IFRIC 21 Levies, if incurred separately. The exception requires entities to apply the criteria in IAS 37 or IFRIC 21, respectively, instead of the Conceptual Framework, to determine whether a present obligation exists at the acquisition date.

The amendments also add a new paragraph to IFRS 3 to clarify that contingent assets do not qualify for recognition at the acquisition date.

In accordance with the transitional provisions, the Group applies the amendments prospectively, i.e., to business combinations occurring after the beginning of the annual reporting period in which it first applies the amendments (the date of initial application).

These amendments had no impact on the Consolidated Financial Statements of the Group as there were no business combinations during the reporting period.

Property, Plant and Equipment: Proceeds before Intended Use – Amendments to IAS 16 Leases

The amendment prohibits entities from deducting from the cost of an item of property, plant and equipment, any proceeds of the sale of items produced while bringing that asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the costs of producing those items, in profit or loss.

In accordance with the transitional provisions, the Group applies the amendments retrospectively only to items of PP&E made available for use on or after the beginning of the earliest period presented when the entity first applies the amendment (the date of initial application).

These amendments had no significant impact on the Consolidated Financial Statements of the Group as there were only sales of such items produced by property, plant and equipment made available for use in Ecuador during 2022.

IFRS 1 First-time Adoption of International Financial Reporting Standards – Subsidiary as a first-time adopter

The amendment permits a subsidiary that elects to apply paragraph of IFRS 1 to measure cumulative translation differences using the amounts reported in the parent's consolidated financial statements, based on the parent's date of transition to IFRS, if no adjustments were made for consolidation procedures and for the effects of the business combination in which the parent acquired the subsidiary. This amendment is also applied to an associate or joint venture that elects to apply paragraph of IFRS 1.

These amendments had no impact on the Consolidated Financial Statements of the Group as it is not a first-time adopter.

IFRS 9 Financial Instruments – Fees in the '10 per cent' test for derecognition of financial liabilities

The amendment clarifies the fees that an entity includes when assessing whether the terms of a new or modified financial liability are substantially different from the terms of the original financial liability. These fees include only those paid or received between the borrower and the lender, including fees paid or received by either the borrower or lender on the other's behalf. There is no similar amendment proposed for IAS 39 Financial Instruments: Recognition and Measurement.

In accordance with the transitional provisions, the Group applies the amendment to financial liabilities that are modified or exchanged on or after the beginning of the annual reporting period in which the entity first applies the amendment (the date of initial application). These amendments had no impact on the Consolidated Financial Statements of the Group as there were no modifications of the Group's financial instruments during the period.

2.1.1.2 Standards issued but not yet effective

The new and amended standards and interpretations that are issued, but not yet effective, up to the date of issuance of these Consolidated Financial Statements are disclosed below. The Group intends to adopt these new and amended standards and interpretations, if applicable, when they become effective.

Classification of Liabilities as Current or Non-current – Amendments to IAS 1

In January 2020, the IASB issued amendments to paragraphs 69 to 76 of IAS 1 to specify the requirements for classifying liabilities as current or non-current. The amendments clarify:

- what is meant by a right to defer settlement,
- that a right to defer must exist at the end of the reporting period,
- that classification is unaffected by the likelihood that an entity will exercise its deferral right, and
- that only if an embedded derivative in a convertible liability is itself an equity instrument would the terms of a liability not impact its classification.

The amendments are effective for annual periods beginning on or after January 1, 2023 and must be applied retrospectively. The Group is currently assessing the impact the amendments will have on current practice and whether existing loan agreements may require renegotiation.

Definition of Accounting Estimates - Amendments to IAS 8

In February 2021, the IASB issued amendments to IAS 8, in which it introduces a definition of 'accounting estimates'. The amendments clarify the distinction between changes in accounting estimates and changes in accounting policies and the correction of errors. Also, they clarify how entities use measurement techniques and inputs to develop accounting estimates.

The amendments are effective for annual periods beginning on or after January 1, 2023 and apply to changes in accounting policies and changes in accounting estimates that occur on or after the start of that period. Earlier application is permitted as long as this fact is disclosed.

The amendments are not expected to have a material impact on the Group's Consolidated Financial Statements.

Disclosure of Accounting Policies - Amendments to IAS 1 and IFRS Practice Statement 2

In February 2021, the IASB issued amendments to IAS 1 and IFRS Practice Statement 2 Making Materiality Judgements, in which it provides guidance and examples to help entities apply materiality judgements to accounting policy disclosures. The amendments aim to help entities provide accounting policy disclosures that are more useful by replacing the requirement for entities to disclose their 'significant' accounting policies with a requirement to disclose their 'material' accounting policies and adding guidance on how entities apply the concept of materiality in making decisions about accounting policy disclosures.

The amendments to IAS 1 are applicable for annual periods beginning on or after January 1, 2023 with earlier application permitted. Since the amendments to the Practice Statement 2 provide non-mandatory guidance on the application of the definition of material to accounting policy information, an effective date for these amendments is not necessary.

The Group is currently revisiting their accounting policy information disclosures to ensure consistency with the amended requirements.

2.2 Going concern

The Directors regularly monitor the Group's cash position and liquidity risks throughout the year to ensure that it has sufficient funds to meet forecasted operational and investment funding requirements. Sensitivities are run to reflect latest expectations of expenditures, oil and gas prices and other factors to enable the Group to manage the risk of any funding short falls and/or potential debt covenant breaches.

Considering the performance of the operations, the Group's cash position of US$ 128,843,000, the oil hedge strategy to mitigate the price risk exposure within the next twelve months, the deleveraging process executed in 2021 and 2022 (see Note 27), and the fact that its total indebtedness as of December 31, 2022 matures in 2027, the Directors have formed a judgement, at the time of approving the Consolidated Financial Statements, that there is a reasonable expectation that the Group has adequate resources to meet all its obligations for the foreseeable future. For this reason, the Directors have continued to adopt the going concern basis in preparing the Consolidated Financial Statements.

2.3 Consolidation

Subsidiaries are all entities (including structured 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 over 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.

Intercompany transactions, balances and unrealized gains on transactions between the Group and its subsidiaries are eliminated. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred. Amounts reported in the financial statements of subsidiaries have been adjusted where necessary to ensure consistency with the accounting policies adopted by the Group.

2.4 Segment reporting

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 allocating resources and assessing performance of the operating segments, has been identified as the Executive Committee. This committee is integrated by the Chief Executive Officer, Chief Financial Officer, Chief Technical Officer, Chief Operating Officer, Chief Strategy, Sustainability and Legal Officer and Chief People Officer. This committee reviews the Group's internal reporting in order to assess performance and allocate resources. Management has determined the operating segments based on these reports.

2.5 Foreign currency translation

2.5.1 Functional and presentation currency

The Consolidated Financial Statements are presented in US Dollars, which is the Group's presentation currency.

Items included in the Consolidated Financial Statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The functional currency of Group companies incorporated in Colombia, Chile, Argentina and Ecuador is the US Dollar, meanwhile for the Group´s Brazilian company the functional currency is the local currency, which is the Brazilian Real.

2.5.2 Transactions and balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at period-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the Consolidated Statement of Income.

The results and financial position of foreign operations 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 closing rate, and income and expenses are translated at average exchange rates. All resulting exchange differences are recognized in Other comprehensive income.

2.6 Joint arrangements

Under IFRS 11, investments in joint arrangements are classified as either joint operations or joint ventures depending on the contractual rights and obligations of each investor. The Group has assessed the nature of its joint arrangements and determined them to be joint operations. The Group combines its share in the joint operations individual assets, liabilities, results and cash flows on a line-by-line basis with similar items in its Consolidated Financial Statements.

2.7 Business combinations

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, which is measured at the acquisition date fair value, and the amount of any non-controlling interests in the acquiree. For each business combination, the Group elects whether to measure the non-controlling interests in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition-related costs are expensed as incurred and included in administrative expenses.

The Group determines that it has acquired a business when the acquired set of activities and assets include an input and a substantive process that together significantly contribute to the ability to create outputs. The acquired process is considered substantive if it is critical to the ability to continue producing outputs, and the inputs acquired include an organized workforce with the necessary skills, knowledge, or experience to perform that process or it significantly contributes to the ability to continue producing outputs and is considered unique or scarce or cannot be replaced without significant cost, effort, or delay in the ability to continue producing outputs.

When the Group acquires a business, it assesses the financial assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

Any contingent consideration to be transferred by the acquirer will be recognized at fair value at the acquisition date. Contingent consideration classified as equity is not remeasured and its subsequent settlement is accounted for within equity. Contingent consideration classified as an asset or liability that is a financial instrument and within the scope of IFRS 9 Financial Instruments, is measured at fair value with the changes in fair value recognized in the statement of profit or loss in accordance with IFRS 9. Other contingent consideration that is not within the scope of IFRS 9 is measured at fair value at each reporting date with changes in fair value recognized in profit or loss.

Goodwill is initially measured at cost (being the excess of the aggregate of the consideration transferred and the amount recognized for non-controlling interests and any previous interest held over the net identifiable assets acquired and liabilities assumed). If the fair value of the net assets acquired is in excess of the aggregate consideration transferred, the Group re-assesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognized at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, then the gain is recognized in profit or loss.

2.8 Revenue recognition

Revenue from the sale of crude oil and gas is recognized at the point in time when control of the product is transferred to the customer, which is generally when the product is physically transferred into a pipe or other delivery mechanism and the customer accepts the product. Consequently, the Group's performance obligations are considered to relate only to the sale of crude oil and gas, with each barrel of crude oil equivalent considered to be a separate performance obligation under the contractual arrangements in place.

The Group's sales of crude oil are priced based on market prices. The sales price is linked to US dollar denominated crude oil international benchmarks, such as Brent, adjusted for certain marketing and quality discounts based on, among other things, American Petroleum Institute ("API") gravity, viscosity, sulphur content, delivery point and transport costs. The Group's sales of natural gas are priced based on long-term Gas Supply contracts with customers.

Revenue is shown net of VAT, discounts related to the sale and overriding royalties due to the ex-owners of oil and gas properties where the royalty arrangements represent a retained working interest in the property. See Note 33.1.

2.9 Production and operating costs

Production and operating costs are recognized in the Consolidated Statement of Income on the accrual basis of accounting. These costs include wages and salaries incurred to achieve the revenue for the year. Direct and indirect costs of raw materials and consumables, rentals, and royalties are also included within this account.

2.10 Financial results

Financial results include interest expenses, interest income, bank charges, the amortization of financial assets and liabilities, and foreign exchange gains and losses. The Group has capitalized the borrowing cost directly attributable to wells and facilities identified as qualifying assets, if applicable. Qualifying assets are assets that necessarily take a substantial period of time to get ready for their intended use or sale. The capitalization rate used to determine the amount of borrowing costs to be capitalized, if any, is the weighted average interest rate applicable to the Group's general borrowings.

2.11 Property, plant and equipment

Property, plant and equipment are stated at historical cost less depreciation and impairment charges, if applicable. Historical cost includes expenditure that is directly attributable to the acquisition of the items; including provisions for asset retirement obligation.

Oil and gas exploration and production activities are accounted for in accordance with the successful efforts method on a field by field basis. The Group accounts for exploration and evaluation activities in accordance with IFRS 6, Exploration for and Evaluation of Mineral Resources, capitalizing exploration and evaluation costs until such time as the economic viability of producing the underlying resources is determined. Costs incurred prior to obtaining legal rights to explore are expensed immediately to the Consolidated Statement of Income.

Exploration and evaluation costs may include: license acquisition, geological and geophysical studies (i.e.: seismic), direct labor costs and drilling costs of exploratory wells. No depreciation and/or amortization are charged during the exploration and evaluation phase. Upon completion of the evaluation phase, the prospects are either transferred to oil and gas properties or charged to expense (exploration costs) in the period in which the determination is made, depending whether they have discovered reserves or not. If not developed, exploration and evaluation assets are written off after three years, unless it can be clearly demonstrated that the carrying value of the investment is recoverable.

A charge of US$ 25,789,000 has been recognized in the Consolidated Statement of Income within Write-off of unsuccessful exploration efforts (US$ 12,262,000 in 2021 and US$ 52,652,000 in 2020). See Note 20.

All field development costs are considered construction in progress until they are finished and capitalized within oil and gas properties, and are subject to depreciation once completed. Such costs may include the acquisition and installation of production facilities, development drilling costs (including dry holes, service wells and seismic surveys for development purposes), project-related engineering and the acquisition costs of rights and concessions related to proved properties.

Workovers of wells made to develop reserves and/or increase production are capitalized as development costs. Maintenance costs are charged to the Consolidated Statement of Income when incurred.

Capitalized costs of proved oil and gas properties and production facilities and machinery are depreciated on a licensed area by the licensed area basis, using the unit of production method, based on commercial proved and probable oil and gas reserves. The calculation of the "unit of production" depreciation considers estimated future finding and development costs and is based on current year-end unescalated price levels. Changes in reserves and cost estimates are recognized prospectively. Reserves are converted to equivalent units on the basis of approximate relative energy content.

Depreciation of the remaining property, plant and equipment assets (i.e. furniture and vehicles) not directly associated with oil and gas activities has been calculated by means of the straight-line method by applying such annual rates as required to write-off their value at the end of their estimated useful lives. The useful lives range between 3 years and 10 years.

Depreciation is allocated in the Consolidated Statement of Income as a separate line to better follow the performance of the business.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount (see Impairment of non-financial assets in Note 2.13).

2.12 Provisions and other long-term liabilities

Provisions for asset retirement obligations and other environmental liabilities, deferred income, restructuring obligations and legal claims are recognized when the Group has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and the amount has been reliably estimated. Restructuring provisions, if any, comprise lease termination penalties and employee services termination payments.

Provisions are measured at the present value of the expenditures expected to be required to settle the obligation using a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the obligation. The increase in the provision due to the passage of time is recognized as financial expense.

2.12.1 Asset Retirement Obligation

The Group records the fair value of the liability for asset retirement obligations in the period in which the wells are drilled. When the liability is initially recorded, the Group capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value at each reporting period, and the capitalized cost is depreciated over the estimated useful life of the related asset. According to interpretations and the application of current legislation, and on the basis of the changes in technology and the variations in the costs of restoration necessary to protect the environment, the Group has considered it appropriate to periodically re-evaluate future costs of well-capping. The effects of this recalculation are included in the Consolidated Financial Statements in the period in which this recalculation is determined and reflected as an adjustment to the provision and the corresponding property, plant and equipment asset.

2.12.2 Deferred Income

Government grants and other contributions relating to the purchase of property, plant and equipment are included in non-current liabilities as deferred income and they are credited to the Consolidated Statement of Income over the expected lives of the related assets. Grants from the government are recognized at their fair value where there is a reasonable assurance that the grant will be received and the Group will comply with all attached conditions.

2.13 Impairment of non-financial assets

Assets that are not subject to depreciation and/or amortization are tested annually for impairment. Assets that are subject to depreciation and/or amortization are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

An impairment loss is recognized for the excess of the asset's carrying amount over its recoverable amount. The 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 flows (cash-generating units), generally a licensed area. Non-financial assets other than goodwill that suffered impairment are reviewed for possible reversal of the impairment at each reporting date.

No asset should be kept as an exploration and evaluation asset for a period of more than three years, except if it can be clearly demonstrated that the carrying value of the investment will be recoverable.

During 2022, no impairment losses were recognized or reversed. Net impairment losses were recognized for US$ 4,334,000 and US$ 133,864,000 in 2021 and 2020, respectively. See Note 37. The write-offs are detailed in Note 20.

2.14 Lease contracts

The Group assesses at contract inception whether a contract is, or contains, a lease. That is, if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

2.14.1 Right-of-use assets

The Group recognizes right-of-use assets at the commencement date of the lease. Right of use assets are measured at cost, less any accumulated depreciation and impairment losses, an adjusted for any measurement of lease liabilities.

The cost of right-of-use assets comprise the following:

- the amount of the initial measurement of lease liability,
- any lease payments made at or before the commencement date less any lease incentives received,
- any initial direct costs, and
- restoration costs.

The Group leases various offices, facilities, machinery and equipment. Lease contracts are typically made for fixed periods of 1 to 15 years but may have extension options. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Right-of-use assets are depreciated on a straight-line basis over the shorter of the lease term and the estimated useful lives of the assets.

If ownership of the leased asset transfers to the Group at the end of the lease term or the cost reflects the exercise of a purchase option, depreciation is calculated using the estimated useful life of the asset. The right-of-use assets are also subject to impairment.

2.14.2 Lease liabilities

At the commencement date of the lease, the Group recognizes lease liabilities measured at the present value of lease payments to be made over the lease term. Lease liabilities include the net present value of the following lease payments:

- fixed payments, less any lease incentives receivable,
- variable lease payments that are based on an index or a rate,
- amounts expected to be payable by the lessee under residual value guarantees,
- the exercise price of a purchase option if the lessee is reasonably certain to exercise that option, and
- payments of penalties for terminating the lease, if the lease term reflects the lessee exercising that option.

In calculating the present value, the lease payments are discounted using the interest rate implicit in the lease. If that rate cannot be determined, the Group’s incremental borrowing rate is used, being the rate that the lessee would have to pay to borrow the funds necessary to obtain an asset of similar value in a similar economic environment with similar terms and conditions. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g., changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset.

2.14.3 Short-term leases and leases of low-value assets

The Group applies the short-term lease recognition exemption to its short-term leases of machinery and equipment (i.e., those leases that have a lease term of 12 months or less from the commencement date and do not contain a purchase option). It also applies the lease of low-value assets recognition exemption to leases of IT equipment and small items of office furniture that are considered to be low value. Lease payments on short-term leases and leases of low-value assets are recognized as expense on a straight-line basis over the lease term.

2.15 Inventories

Inventories comprise crude oil and materials.

Crude oil is measured at the lower of cost and net realizable value. Materials are measured at the lower of cost and recoverable amount. The cost of materials and consumables is calculated at acquisition price with the addition of transportation and similar costs. Cost is determined using the first-in, first-out (FIFO) method.

2.16 Current and deferred income tax

The tax expense for the year comprises current and deferred income tax. Income tax is recognized in the Consolidated Statement of Income.

The current income tax charge is calculated on the basis of the tax laws enacted or substantially enacted at the financial statements date in the countries where the Company's subsidiaries operate and generate taxable income. The computation of the income tax expense involves the interpretation of applicable tax laws and regulations in many jurisdictions. The resolution of tax positions taken by the Group, through negotiations with relevant tax authorities or through litigation, can take several years to complete and, in some cases, it is difficult to predict the ultimate outcome.

Deferred income tax is recognized, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Consolidated Financial Statements. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted as of the financial statements date and are expected to apply when the related deferred income tax asset is realized, or the deferred income tax liability is settled.

In addition, the Group has tax-loss carry-forwards in certain tax jurisdictions that are available to be offset against future taxable profit. However, deferred income tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses can be utilized. Management judgment is exercised in assessing whether this is the case. To the extent that actual outcomes differ from management's estimates, taxation charges or credits may arise in future periods.

Deferred income tax liabilities are provided on taxable temporary differences arising from investments in subsidiaries and joint arrangements, except for deferred income tax liability where the timing of the reversal of the temporary difference is controlled by the Group and it is probable that the temporary difference will not reverse in the foreseeable future. The Group is able to control the timing of dividends from its subsidiaries and hence does not expect taxable profit. Hence deferred income tax is recognized in respect of the retained earnings of overseas subsidiaries only if at the date of the Consolidated Financial Statements, dividends have been accrued as receivable or a binding agreement to distribute past earnings in future has been entered into by the subsidiary. As mentioned above the Group does not expect that the temporary differences will revert in the foreseeable future.

Deferred income tax balances are provided in full, with no discounting.

2.17 Non-current assets or disposal groups held for sale

Non-current assets or disposal groups are classified as held for sale if their carrying amount will be recovered principally through a sale transaction rather than through continuing use and a sale is considered highly probable. They are measured at the lower of their carrying amount and fair value less costs to sell, except for assets such as deferred tax assets, assets arising from employee benefits, financial assets and investment property that are carried at fair value and contractual rights under insurance contracts, which are specifically exempt from this requirement.

An impairment loss is recognized for any initial or subsequent write-down of the asset or disposal group to fair value less costs to sell. A gain is recognized for any subsequent increases in fair value less costs to sell of an asset or disposal group, but not in excess of any cumulative impairment loss previously recognized. A gain or loss not previously recognized by the date of the sale of the non-current asset or disposal group is recognized at the date of derecognition.

Non-current assets (including those that are part of a disposal group) are not depreciated or amortized while they are classified as held for sale. Interest and other expenses attributable to the liabilities of a disposal group classified as held for sale continue to be recognized.

Non-current assets classified as held for sale and the assets of a disposal group classified as held for sale are presented separately from the other assets in the Consolidated Statement of Financial Position. The liabilities of a disposal group classified as held for sale are presented separately from other liabilities in the Consolidated Statement of Financial Position.

2.18 Financial assets

Financial assets are divided into the following categories: amortized cost; financial assets at fair value through profit or loss and fair value through other comprehensive income. The classification depends on the Group's business model for managing the financial assets and the contractual terms of the cash flows. The Group reclassifies debt investments when and only when its business model for managing those assets changes.

All financial assets not at fair value through profit or loss are initially recognized at fair value, plus transaction costs. Transaction costs of financial assets carried at fair value through profit or loss, if any, are expensed to profit or loss.

Derecognition of financial assets occurs when the rights to receive cash flows from the investments expire or are transferred and substantially all of the risks and rewards of ownership have been transferred. An assessment for impairment is undertaken at each balance sheet date.

Interest and other cash flows resulting from holding financial assets are recognized in the Consolidated Statement of Income when receivable, regardless of how the related carrying amount of financial assets is measured.

Amortized cost are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for maturities greater than twelve months after the balance sheet date. These are classified as non-current assets. These financial assets comprise trade and other receivables and cash and cash equivalents in the Consolidated Statement of Financial Position. They arise when the Group provides money, goods or services directly to a debtor with no intention of trading the receivables. These financial assets are subsequently measured at amortized cost using the effective interest method, less provision for impairment, if applicable.

Any change in their value through impairment or reversal of impairment is recognized in the Consolidated Statement of Income. All of the Group's financial assets are classified as amortized cost.

2.19 Other financial assets

Non-current other financial assets include contributions made for environmental obligations according to a Colombian and Brazilian government request and are restricted for those purposes.

Current other financial assets include short-term investments with original maturities up to twelve months and over three months.

2.20 Impairment of financial assets

The Group assesses on a forward-looking basis the expected credit losses associated with its debt instruments. The impairment methodology applied depends on whether there has been a significant increase in credit risk. For trade receivables, the Group applies the simplified approach permitted by IFRS 9, which requires expected lifetime losses to be recognized from initial recognition of the receivables.

2.21 Cash and cash equivalents

Cash and cash equivalents includes cash in hand, deposits held at call with banks, other short-term highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value, and bank overdrafts. Bank overdrafts, if any, are shown within borrowings in the current liabilities section of the Consolidated Statement of Financial Position.

2.22 Trade and other payables

Trade payables are obligations to pay for goods or services that have been acquired in the ordinary course of the business from suppliers. Accounts payable are classified as current liabilities if payment is due within one year or less (or in the normal operating cycle of the business if longer). If not, they are presented as non-current liabilities.

Trade payables are recognized initially at fair value and subsequently measured at amortized cost using the effective interest method.

2.23 Derivatives and hedging activities

Derivative financial instruments are recognized in the Consolidated Statement of Financial Position as assets or liabilities and initially and subsequently measured at fair value. They are presented as current assets or liabilities if they are expected to be settled within 12 months after the end of the reporting period.

The mark-to-market fair value of the Group's outstanding derivative instruments is based on independently provided market rates and determined using standard valuation techniques, including the impact of counterparty credit risk and are within level 2 of the fair value hierarchy.

2.23.1 Cash flow hedges that qualify for hedge accounting

The effective portion of changes in the fair value of derivatives that are designated and qualify as cash flow hedges is recognized in Other Reserve within Equity. The gain or loss relating to the ineffective portion is recognized immediately in the Consolidated Statement of Income.

When forward contracts are used to hedge forecast transactions, the Group designates the change in fair value of the forward contract as the hedging instrument. Gains or losses relating to the effective portion of the change in the fair value of the forward contracts are recognized in Other Reserve within Equity.

Where the hedged item subsequently results in the recognition of a non-financial asset, both the deferred hedging gains and losses and the deferred time value of the option contracts or deferred forward points, if any, are included within the initial cost of the asset.

When a hedging instrument expires, or is sold or terminated, or when a hedge no longer meets the criteria for hedge accounting, any cumulative deferred gain or loss and deferred costs of hedging in Equity at that time remains in Equity until the forecast transaction occurs, resulting in the recognition of a non-financial asset. When the forecast transaction is no longer expected to occur, the cumulative gain or loss and deferred costs of hedging that were reported in Equity are immediately reclassified to the Consolidated Statement of Income.

For more information about derivatives designated as cash flow hedges please refer to Note 36.1 and Note 8.

2.23.2 Other Derivatives

Certain derivative instruments do not qualify for hedge accounting. Changes in the fair value of any derivative instrument that does not qualify for hedge accounting are recognized immediately in the Consolidated Statement of Income.

For more information about derivatives related to commodity risk management please refer to Note 8 and for more information about derivatives related to currency risk management please refer to Note 3 Currency risk.

2.24 Borrowings

Borrowings are obligations to pay cash and are recognized when the Group becomes a party to the contractual provisions of the instrument.

Borrowings are recognized initially at fair value, net of transaction costs incurred. Borrowings are subsequently stated at amortized cost; any difference between the proceeds (net of transaction costs) and the redemption value is recognized in the Consolidated Statement of Income over the period of the borrowings using the effective interest method.

Direct issue costs are charged to the Consolidated Statement of Income on an accrual basis using the effective interest method.

2.25 Share capital

Equity comprises the following:

- "Share capital" representing the nominal value of equity shares.
- "Share premium" representing the excess over nominal value of the fair value of consideration received for equity shares, net of expenses of the share issuance.
- "Other reserve" representing:
    - the difference between the proceeds from the transaction with non-controlling interests received against the book value of the shares acquired in the Chilean and Colombian subsidiaries, and
    - the changes in the fair value of the effective portion of derivatives designated as cash flow hedges.
- "Translation reserve" representing the differences arising from translation of investments in overseas subsidiaries.
- "(Accumulated losses) Retained earnings" representing:
    - accumulated earnings and losses, and
    - the equity element attributable to shares granted according to IFRS 2 but not issued at year end.

2.26 Share-based payment

The Group operates a number of equity-settled share-based compensation plans comprising share awards payments to employees and other third-party contractors. Share-based payment transactions are measured in accordance with IFRS 2.

The fair value of the share awards payments is determined at the grant date by reference to the market value of the shares, calculated using the Geometric Brownian Motion method or the Monte Carlo simulation, and recognized as an expense over the vesting period.

Service and non-market performance conditions are not taken into account when determining the grant date fair value of awards, but the likelihood of the conditions being met is assessed as part of the Group’s best estimate of the number of equity instruments that will ultimately vest. Market performance conditions are reflected within the grant date fair value. Any other conditions attached to an award, but without an associated service requirement, are considered to be non-vesting conditions. Non-vesting conditions are reflected in the fair value of an award and lead to an immediate expensing of an award unless there are also service and/or performance conditions.

No expense is recognized for awards that do not ultimately vest because non-market performance and/or service conditions have not been met. Where awards include a market or non-vesting condition, the transactions are treated as vested irrespective of whether the market or non-vesting condition is satisfied, provided that all other performance and/or service conditions are satisfied.

At each reporting date, the entity revises its estimates of the number of options that are expected to vest. It recognizes the impact of the revision to original estimates, if any, in the Consolidated Statement of Income, with a corresponding adjustment to equity.

When the awards are exercised, the Company issues new shares. The proceeds received net of any directly attributable transaction costs are credited to share capital (nominal value) and share premium.

Note 3 Financial Instruments-risk management

The Group is exposed through its operations to the following financial risks:

- Currency risk
- Price risk
- Credit risk– concentration
- Funding and liquidity risk
- Interest rate risk
- Capital risk

The policy for managing these risks is set by the board of directors. Certain risks are managed centrally, while others are managed locally following guidelines communicated from the corporate department. The policy for each of the above risks is described in more detail below.

Currency risk

In Colombia, Chile, Argentina and Ecuador the functional currency is the US Dollar. The fluctuation of the local currencies of these countries against the US Dollar, except for Ecuador where the local currency is the US Dollar, does not impact the loans, costs and revenue held in US Dollars; but it does impact receivables or payables originated in local currency mainly corresponding to VAT and income tax.

The Group minimises the local currency positions in Colombia, Chile and Argentina by seeking to balance local and foreign currency assets and liabilities. However, tax receivables (VAT) seldom match with local currency liabilities. Therefore, the Group maintains a net exposure to them, except for what it is described below.

Since December 2018, GeoPark decided to manage its future exposure to local currency fluctuation with respect to income tax balances in Colombia. Consequently, from time to time the Group entered into derivative financial instruments in order to anticipate any currency fluctuation with respect to income taxes to be paid during the first half of the following year. As of December 31, 2022 and 2021, there were no currency risk management contracts in place. In 2023, GeoPark entered into derivative financial instruments (zero-premium collars) with local banks in Colombia, for an amount equivalent to US$ 38,000,000, in order to anticipate any currency fluctuation with respect to a portion of the estimated income taxes to be paid in April and June 2023.

Most of the Group's assets held in those countries are associated with oil and gas productive assets. Those assets, even in the local markets, are generally settled in US Dollar equivalents.

During 2022, the Colombian Peso devalued by 21% (16% and 5% in 2021 and 2020, respectively) and the Chilean Peso devalued by 1% (devalued by 19% in 2021 and revalued by 5% in 2020), both against the US Dollar.

If the Colombian Peso and the Chilean Peso had each devalued an additional 10% against the US dollar, with all other variables held constant, post-tax profit for the year would have been higher by US$ 14,695,000 (post-tax profit would have been higher by US$ 9,070,000 in 2021 and post-tax loss would have been lower by US$ 9,057,000 in 2020).

In Brazil, the functional currency is the local currency, which is the Brazilian Real. The fluctuation of the US Dollars against the Brazilian Real does not impact the loans, costs and revenues held in Brazilian Real; but it does impact the balances denominated in US Dollars. Such is the case of the provision for asset retirement obligation and the lease liabilities.

During 2022, the Brazilian Real revalued by 7% against the US Dollar (devalued by 7% and 29% in 2021 and 2020, respectively). If the Brazilian Real had devalued an additional 10% against the US dollar, with all other variables held constant, post-tax profit for the year would have been lower by US$ 726,000 (post-tax profit would have been lower by US$ 780,000 in 2021 and post-tax loss would have been higher by US$ 909,000 in 2020).

As currency rate changes between the US Dollar and the local currencies, the Group recognizes gains and losses in the Consolidated Statement of Income.

Price risk

The realized oil price for the Group is linked to US dollar denominated crude oil international benchmarks. The market price of this commodity is subject to significant volatility and has historically fluctuated widely in response to relatively minor changes in the global supply and demand for oil, the geopolitical landscape, armed conflicts, the economic conditions and a variety of additional factors. The main factors affecting realized prices for gas sales vary across countries with some closely linked to international references while others are more domestically driven.

In Colombia, the realized oil price is linked to either the Vasconia crude reference price, a marker broadly used in the Llanos Basin, or the Oriente crude reference price, a marker broadly used for crude sales in Esmeraldas, Ecuador, for the crude oil of the Putumayo Basin that is transported through Ecuador. In both basins, the reference price is then adjusted for certain marketing and quality discounts based on, among other things, API, viscosity, sulphur content, delivery point and transport costs.

In Chile, the oil price is linked to Dated Brent minus certain marketing and quality discounts such as, API, sulphur content and others.

GeoPark has signed a long-term Gas Supply Contract with Methanex in Chile. The price of the gas sold under this contract is determined by a formula that considers a basket of international methanol prices, including US and European price indices.

In Brazil, prices for gas produced in the Manati Field are based on a long-term off-take contract with Petrobras. The price of gas sold under this contract is denominated in Brazilian Real and is adjusted annually for inflation pursuant to the Brazilian General Market Price Index (Indice Geral de Preços do Mercado), or IGPM.

In Ecuador, the oil price is linked to Brent and adjusted by a differential that varies month to month and resembles Oriente crude reference.

If oil and methanol prices had fallen by 10% compared to actual prices during the year, with all other variables held constant, considering the impact of the derivative contracts in place, post-tax profit for the year would have been lower by US$ 47,330,000 (post-tax profit would have been lower by US$ 17,899,000 in 2021 and post-tax loss would have been higher by US$ 21,014,000 in 2020).

GeoPark manages part of the exposure to crude oil price volatility using derivatives. The Group considers these derivative contracts to be an effective manner of properly managing commodity price risk. The price risk management activities mainly employ combinations of options and key parameters are based on forecasted production and budget price levels.

GeoPark has also obtained credit lines from industry leading counterparties to minimize the potential cash exposure of the derivative contracts (see Note 8).

Credit risk– concentration

The Group's credit risk relates mainly to accounts receivable where the credit risks correspond to the recognized values of commodities sold or hedged. GeoPark considers that there is no significant risk associated to the Group's major customers and hedging counterparties.

In Colombia, GeoPark allocates its sales on a competitive basis to industry leading participants including traders and other producers. During 2022, the oil and gas production was sold to three clients which concentrate 97% of the Colombian subsidiaries' revenue, accounting for 90% of the consolidated revenue (99% and 98% of the Colombian subsidiaries' revenue, accounting for 89% and 83% of the consolidated revenue in 2021 and 2020). Delivery points include wellhead and other locations on the Colombian pipeline system for the Llanos Basin production. The Putumayo Basin production is delivered to clients FOB in Esmeraldas, Ecuador, and to the Colombian pipeline system in case of contingencies in Ecuador that affect the transport through the Ecuadorian pipeline system. The outstanding contracts for Colombian production extend through the first half of 2023. GeoPark manages its counterparty credit risk associated to sales contracts by periodic evaluation of the counterparties' credit profile and, in certain contracts, including early payment conditions to minimize the exposure.

In Chile, the oil production is sold to ENAP, the State-owned oil and gas company (1% of the consolidated revenue in 2022, 2021 and 2020), and the gas production is sold to the local subsidiary of Methanex, a Canadian public company (1% of the consolidated revenue in 2022, 2% in 2021 and 4% in 2020).

In Brazil, all the hydrocarbons from Manati Field are sold to Petrobras, the State-owned company, which is the operator of the Manati Field (2% of the consolidated revenue in 2022, 3% in 2021 and 2020).

In Ecuador, oil is transported through the Ecuadorean pipeline system, with Esmeraldas as the delivery point, and 100% of the sales are exported on a competitive basis to industry leading participants including traders and other producers. Sales of crude oil in Ecuador accounted for 1% of the consolidated revenue in 2022.

GeoPark Limited has entered into a crude purchase agreement with an oil producer in the Putumayo Basin. The volumes purchased are transported and exported alongside the Group's Putumayo Basin production. Sales of crude oil purchased from third parties accounted for 1% of the consolidated revenue in 2022.

The forementioned companies all have a good credit standing and despite the concentration of the credit risk, the Directors do not consider there to be a significant collection risk.

GeoPark executes oil prices hedges via over-the-counter derivatives. Should oil prices drop, the Group could stand to collect from its counterparties under the derivative contracts. The Group's hedging counterparties are leading financial institutions and trading companies, therefore the Directors do not consider there to be a significant collection risk. See disclosure in Notes 8 and 25.

Funding and Liquidity risk

In the past, the Group has been able to raise capital through different sources of funding including equity, strategic partnerships and financial debt.

The Group is positioned at the end of 2022 with a cash balance of US$ 128,843,000 and its total indebtedness matures in 2027. In addition, the Group has a large portfolio of attractive and largely discretional projects - both oil and gas - in multiple countries with 37,700 boepd in production at year end. This scale and positioning permit the Group to protect its financial condition and selectively allocate capital to the optimal projects subject to prevailing macroeconomic conditions.

The Indentures governing the Company Notes 2027 include incurrence test covenants related to compliance with certain thresholds of Net Debt to Adjusted EBITDA ratio and Adjusted EBITDA to Interest ratio. Failure to comply with the incurrence test covenants does not trigger an event of default. However, this situation may limit the Group's capacity to incur additional indebtedness, as specified in the indentures governing the Notes. As of the date of these Consolidated Financial Statements, the Group is in compliance with all the indentures' provisions and covenants.

Interest rate risk

The Group's interest rate risk could arise from long-term borrowings issued at variable rates, which would expose the Group to interest rate risk.

The Group does not face interest rate risk on its US$ 500,000,000 Notes which carry a fixed rate coupon of 5.50% per annum. Consequently, the accruals and interest payments are not substantially affected by the market interest rate changes.

As of December 31, 2022, there were no outstanding borrowings affected by a variable rate.

Capital risk

The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern in order to provide returns for shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital.

Consistent with others in the industry, the Group monitors capital on the basis of the gearing ratio. This ratio is calculated as net debt divided by total capital. Net debt is calculated as total borrowings (including 'current and non-current borrowings' as shown in the Consolidated Statement of Financial Position) less cash and cash equivalents. Total capital is calculated as 'equity' as shown in the Consolidated Statement of Financial Position plus net debt.

The Group's strategy is to keep the gearing ratio within a 60% to 80% range, in normal market conditions. Due to the market conditions prevailing in 2021, the gearing ratio was above such range at that year-end.

The gearing ratios as of December 31, 2022 and 2021 were as follows:

Amounts in US$'000	2022	2021
Net Debt	368,799	573,488
Total Equity	115,585	(61,945)
Total Capital	484,384	511,543
Gearing Ratio	76%	112%

Note 4 Accounting estimates and assumptions

Estimates and assumptions are used in preparing financial statements. Although these estimates are based on management's best knowledge of current events and actions, actual results may differ. Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

The key estimates and assumptions used in these Consolidated Financial Statements are noted below:

- The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. The estimation of economically recoverable oil and natural gas reserves and related future net cash flows was performed based on the Reserve Report as of December 31, 2022 prepared by DeGolyer and MacNaughton Corp., an independent international oil and gas consulting firm based in Dallas, Texas, in line with the principles contained in the Society of Petroleum Engineers (SPE) and the Petroleum Resources Management Reporting System (PRMS) framework.

It incorporates many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality differentials;
- assumed effects of regulation by governmental agencies;
- tax rates by jurisdiction; and
- future development and operating costs.

Management believes these factors and assumptions are reasonable based on the information available to them at the time of preparing the estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Such changes may impact the Group's reported financial position and results, which include: (a) the carrying value of exploration and evaluation assets, oil and gas properties and other property, plant and equipment may be affected due to changes in estimated future cash flows, (b) depreciation and amortization charges in the Consolidated Statement of Income may change where such charges are determined using the unit of production method, or where the useful life of the related assets change, (c) provisions for abandonment may require revision -where changes to reserves estimates affect expectations about when such activities will occur and the associated cost of these activities- and, (d) the recognition and carrying value of deferred income tax assets may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets.

- Cash flow estimates for impairment assessments of non-financial assets require assumptions about two primary elements: future prices and reserves. Estimates of future prices require significant judgments about highly uncertain future events. Historically, oil and gas prices have exhibited significant volatility. The Group's forecasts for oil and gas revenues are based on prices derived from future price forecasts amongst industry analysts and internal assessments. Estimates of future cash flows are generally based on assumptions of long-term prices and operating and development costs. Given the significant assumptions required and the possibility that actual conditions may differ, management considers the assessment of impairment to be a critical accounting estimate (see Note 37).

- The Group adopted the successful efforts method of accounting. The Management of the Group makes assessments and estimates regarding whether an exploration and evaluation asset should continue to be carried forward as such when insufficient information exists. This assessment is made on a quarterly basis considering the advice from qualified experts.

  The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement to determine whether future economic benefits are likely from future either exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is, in itself, an estimation process that involves varying degrees of uncertainty depending on how the resources are classified. These estimates directly impact when the Group defers exploration and evaluation expenditure. The deferral policy requires management to make certain estimates and assumptions about future events and circumstances, in particular, whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalized amount is written-off in the Consolidated Statement of Income in the period when the new information becomes available.

- Oil and gas assets held in property plant and equipment are mainly depreciated on a unit of production ("UOP") basis at a rate calculated by reference to proven and probable reserves and incorporating the estimated future cost of developing and extracting those reserves. Future development costs are estimated using assumptions as to the numbers of wells required to produce those reserves, the cost of the wells and future production facilities. This results in a depreciation charge proportional to the depletion of the anticipated remaining production from the block.

  The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the block at which the asset is located. These calculations require the use of estimates and assumptions, including the amount of recoverable reserves and estimates of future capital expenditure. The calculation of the UOP rate of depreciation will be impacted to the extent that actual production in the future is different from current forecast production based on total proved and probable reserves, or future capital expenditure estimates change. Changes to proved and probable reserves could arise due to changes in the factors or assumptions used in estimating reserves, including: (a) the effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions and (b) unforeseen operational issues.

- Obligations related to the abandonment of wells once operations are terminated may result in the recognition of significant obligations. Estimating the future abandonment costs is difficult and requires management to make estimates and judgments because most of the obligations are many years in the future. Technologies and costs are constantly changing as well as political, environmental, safety and public relations considerations. The Group has adopted the following criterion for recognizing well plugging and abandonment related costs: the present value of future costs necessary for well plugging and abandonment is calculated for each area at the present value of the estimated future expenditure. The liabilities recognized are based upon estimated future abandonment costs, wells subject to abandonment, time to abandonment, and future inflation rates.

  The expected timing, extent and amount of expenditure may also change, for example, in response to changes in oil and gas reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

  The provision at reporting date represents management's best estimate of the present value of the future abandonment costs required.

- From time to time, the Group may be subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, tax, environmental, safety and health matters. For example, from time to time, the Group receives notice of environmental, health and safety violations. Based on what the Group's Management currently knows, such claims are not expected to have a material impact on the Consolidated Financial Statements.

Note 5 Consolidated Statement of Cash Flow

The Consolidated Statement of Cash Flow shows the Group’s cash flows for the year for operating, investing and financing activities and the change in cash and cash equivalents during the year.

Cash flows from operating activities are computed from the results for the year adjusted for non-cash operating items, changes in net working capital and corporate tax. Income tax paid is presented as a separate item under operating activities.

Cash flows from investing activities include payments in connection with the purchase and sale of property, plant and equipment and cash flows relating to the purchase and sale of enterprises to third parties, if any.

Cash flows from financing activities include changes in equity and proceeds from borrowings and repayment of loans.

Cash and cash equivalents include bank overdraft, if any, and liquid funds with a term of less than three months.

The following chart describes non-cash transactions related to the Consolidated Statement of Cash Flow:

Amounts in US$‘000	**2022**	**2021**	**2020**
Decrease in asset retirement obligation	(4,942)	(651)	(1,812)
Decrease in provisions for other long-term liabilities	(2,616)	(443)	(1,051)
Purchase of property, plant and equipment	7,864	—	—
Additions / changes in estimates of right-of-use assets	22,462	5,288	560

Changes in working capital shown in the Consolidated Statement of Cash Flow are disclosed as follows:

Amounts in US$‘000	**2022**	**2021**	**2020**
(Increase) Decrease in Inventories	(6,694)	1,241	1,220
(Increase) Decrease in Trade receivables	(1,425)	(23,290)	3,190
(Increase) Decrease in Prepayments and other receivables and Other assets [(a)]	(30,929)	(13,817)	38,742
(Decrease) Increase in Trade and other payables	(999)	26,515	(48,392)
	(40,047)	**(9,351)**	**(5,240)**

(a) Includes withholding taxes from clients for US$ 27,256,000, US$ 16,361,000 and US$ 10,046,000, in 2022, 2021 and 2020, respectively.

The following chart shows the movements in the borrowings and lease liabilities for each of the periods presented:

Amounts in US$'000	Borrowings	Lease Liabilities	Total
As of January 1, 2020	**437,419**	**13,243**	**450,662**
Proceeds from borrowings	350,000	—	350,000
Debt issuance costs paid	(7,507)	—	(7,507)
Acquisitions (Note 36.1)	—	17,851	17,851
Addition to lease liabilities	—	561	561
Accrual of borrowing's interests	48,232	—	48,232
Exchange difference	—	466	466
Foreign currency translation	(2,389)	(1,641)	(4,030)
Unwinding of discount	—	1,247	1,247
Principal paid	(3,575)	—	(3,575)
Interest paid	(37,594)	—	(37,594)
Lease payments	—	(9,380)	(9,380)
As of December 31, 2020	**784,586**	**22,347**	**806,933**
Proceeds from borrowings	172,174	—	172,174
Debt issuance costs paid	(2,019)	—	(2,019)
Addition to lease liabilities	—	5,288	5,288
Accrual of borrowing's interests	44,323	—	44,323
Exchange difference	(581)	(365)	(946)
Foreign currency translation	(265)	(461)	(726)
Unwinding of discount	—	1,453	1,453
Principal paid	(274,934)	—	(274,934)
Interest paid	(42,592)	—	(42,592)
Borrowings cancellation costs	6,308	—	6,308
Borrowings cancellation and other costs paid	(12,908)	—	(12,908)
Lease payments	—	(7,518)	(7,518)
As of December 31, 2021	**674,092**	**20,744**	**694,836**
Addition to lease liabilities	—	22,462	22,462
Accrual of borrowing's interests	36,360	—	36,360
Exchange difference	—	(6,426)	(6,426)
Foreign currency translation	203	284	487
Unwinding of discount	—	2,838	2,838
Principal paid	(172,522)	—	(172,522)
Interest paid	(36,514)	—	(36,514)
Borrowings cancellation costs	5,141	—	5,141
Borrowings cancellation and other costs paid	(9,118)	—	(9,118)
Lease payments	—	(7,851)	(7,851)
As of December 31, 2022	**497,642**	**32,051**	**529,693**

Note 6 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 allocating resources and assessing performance of the operating segments, has been identified as the Executive Committee. This committee is integrated by the Chief Executive Officer, Chief Financial Officer, Chief Technical Officer, Chief Operating Officer, Chief Strategy, Sustainability and Legal Officer and Chief People Officer. This committee reviews the Group's internal reporting in order to assess performance and allocate resources. Management has determined the operating segments based on these reports. The committee considers the business from a geographic perspective.

The Executive Committee assesses the performance of the operating segments based on a measure of Adjusted EBITDA. Adjusted EBITDA is defined as profit (loss) for the period (determined as if IFRS 16 Leases has not been adopted), before net finance cost, income tax, depreciation, amortization, certain non-cash items such as impairments and write-offs of unsuccessful exploration efforts, accrual of share-based payment, unrealized result on commodity risk management contracts, geological and geophysical expenses allocated to capitalized projects, and other non-recurring events. Other information provided to the Executive Committee is measured in a manner consistent with that in the Consolidated Financial Statements.

Segment areas (geographical segments)

Amounts in US$ '000	**Colombia**	**Chile**	**Brazil**	**Argentina**	**Ecuador [b]**	**Corporate**	**Total**
2022							
Revenue	978,423	29,196	19,873	1,962	10,671	9,454	1,049,579
Sale of crude oil	977,184	14,460	796	1,664	10,671	—	1,004,775
Sale of purchased crude oil	—	—	—	—	—	9,454	9,454
Sale of gas	1,239	14,736	19,077	298	—	—	35,350
Realized loss on commodity risk management contracts	(83,244)	—	—	—	—	—	(83,244)
Production and operating costs	(327,626)	(14,126)	(5,299)	(1,579)	(3,220)	(7,929)	(359,779)
Royalties	(60,314)	(1,165)	(1,546)	(273)	—	—	(63,298)
Economic rights	(188,989)	—	—	—	—	—	(188,989)
Share-based payment	(843)	(103)	—	1	(10)	—	(955)
Other operating costs	(77,480)	(12,858)	(3,753)	(1,307)	(3,210)	(7,929)	(106,537)
Adjusted EBITDA	525,593	11,753	11,654	(3,643)	4,197	(8,775)	540,779
Depreciation	(78,775)	(14,076)	(2,796)	(254)	(788)	(3)	(96,692)
Write-off of unsuccessful exploration efforts	(21,318)	—	—	—	(4,471)	—	(25,789)
Total assets	797,390	63,379	34,329	1,296	35,690	41,891	973,975
Employees (average) (a)	362	53	5	33	7	9	469
Employees at year end (a)	388	49	4	24	8	9	482

(a) Unaudited

(b) Includes certain expenses that correspond to the Peruvian subsidiary, which acts as a holding company of the Ecuadorian subsidiary since Peru is no longer an operating segment due to the retirement from the Morona Block.

Amounts in US$ '000	Colombia	Chile	Brazil	Argentina	Ecuador [b]	Corporate	Total
2021							
Revenue	618,268	21,471	20,109	28,695	—	—	688,543
Sale of crude oil	616,133	6,297	661	24,468	—	—	647,559
Sale of gas	2,135	15,174	19,448	4,227	—	—	40,984
Realized gain on commodity risk management contracts	(109,654)	—	—	—	—	—	(109,654)
Production and operating costs	(178,384)	(11,050)	(4,596)	(18,760)	—	—	(212,790)
Royalties	(33,385)	(770)	(1,575)	(4,270)	—	—	(40,000)
Economic rights	(72,956)	—	(67)	—	—	—	(73,023)
Share-based payment	(334)	(31)	—	26	—	—	(339)
Other operating costs	(71,709)	(10,249)	(2,954)	(14,516)	—	—	(99,428)
Adjusted EBITDA	294,847	7,639	12,569	2,124	(2,071)	(14,308)	300,800
Depreciation	(61,279)	(14,275)	(4,082)	(9,130)	(200)	(3)	(88,969)
Recognition of impairment losses	—	(17,641)	—	13,307	—	—	(4,334)
Write-off of unsuccessful exploration efforts	(7,827)	(4,435)	—	—	—	—	(12,262)
Total assets	689,401	71,515	38,846	38,111	7,782	50,086	895,741
Employees (average) [a]	308	55	4	92	8	9	476
Employees at year end [a]	321	52	4	74	3	9	463

Amounts in US$ '000	Colombia	Chile	Brazil	Argentina	Peru [c]	Ecuador	Corporate	Total
2020								
Revenue	334,606	21,704	12,783	24,599	—	—	—	393,692
Sale of crude oil	332,461	5,103	891	21,185	—	—	—	359,640
Sale of gas	2,145	16,601	11,892	3,414	—	—	—	34,052
Realized gain on commodity risk management contracts	21,059	—	—	—	—	—	—	21,059
Production and operating costs	(92,319)	(10,244)	(3,876)	(18,633)	—	—	—	(125,072)
Royalties	(15,493)	(753)	(1,025)	(3,620)	—	—	—	(20,891)
Economic rights	(14,960)	—	(24)	—	—	—	—	(14,984)
Share-based payment	(362)	(94)	—	(72)	—	—	—	(528)
Other operating costs	(61,504)	(9,397)	(2,827)	(14,941)	—	—	—	(88,669)
Adjusted EBITDA	218,524	8,148	4,784	1,195	(1,952)	(773)	(12,395)	217,531
Depreciation	(63,687)	(33,571)	(3,732)	(16,564)	(401)	(52)	(66)	(118,073)
Recognition of impairment losses	—	(81,967)	(1,717)	(16,205)	(33,975)	—	—	(133,864)
Write-off of unsuccessful exploration efforts	(1,949)	(50,167)	(536)	—	—	—	—	(52,652)
Total assets	680,828	101,742	38,172	36,803	4,656	1,127	96,938	960,266
Employees (average) [a]	238	68	11	114	10	2	4	447
Employees at year end [a]	268	57	5	97	5	2	3	437

(a) Unaudited.

(b) Includes certain expenses and 4 average employees (who were no longer in the Group at year-end) that corresponded to the Peruvian subsidiaries, which act as holding companies of the Ecuadorian branch since Peru is no longer an operating segment due to the retirement from the Morona Block.

(c) As of the date of these Consolidated Financial Statements, Peru is no longer an operating segment due to the retirement from the Morona Block.

In 2022, approximately 82% of capital expenditure was incurred by Colombia (93% in 2021 and 82% in 2020), 7% was incurred by Chile (3% in 2021 and 16% in 2020), and 11% was incurred by Ecuador (4% in 2021 and 1% in 2020).

A reconciliation of total Adjusted EBITDA to total profit (loss) before income tax is provided as follows:

Amounts in US$ '000	2022	2021	2020
Adjusted EBITDA	**540,779**	**300,800**	**217,531**
Unrealized gain (loss) on commodity risk management contracts	13,023	463	(12,978)
Depreciation [(a)]	(96,692)	(88,969)	(118,073)
Share-based payment	(11,038)	(6,621)	(8,444)
Impairment and write-off of unsuccessful exploration efforts, net	(25,789)	(16,596)	(186,516)
Lease accounting - IFRS 16	7,851	7,518	9,380
Others [(b)]	943	(10,786)	(11,563)
Operating profit (loss)	**429,077**	**185,809**	**(110,663)**
Financial expenses	(57,073)	(64,112)	(64,582)
Financial income	3,180	1,652	3,166
Foreign exchange gain (loss)	19,725	5,049	(13,008)
Profit (Loss) before tax	**394,909**	**128,398**	**(185,087)**

(a) Net of capitalized costs for oil stock included in Inventories.

(b) Includes allocation to capitalized projects. In 2022, also includes gain from the sale of the Aguada Baguales, El Porvenir and Puesto Touquet Blocks in Argentina. In 2021, also includes termination costs and write-down of tax credits in Argentina. In 2020, also includes termination costs, and write-down of VAT credits and recognition of a provision for environmental liabilities in Peru. See Note 36.

Note 7 Revenue

Amounts in US$ '000	2022	2021	2020
Sale of crude oil	1,004,775	647,559	359,640
Sale of purchased crude oil	9,454	—	—
Sale of gas	35,350	40,984	34,052
	1,049,579	**688,543**	**393,692**

Note 8 Commodity risk management contracts

The Group has entered into derivative financial instruments to manage its exposure to oil price risk. These derivatives are zero-premium collars and were placed with major financial institutions and commodity traders. The Group entered into the derivatives under ISDA Master Agreements and Credit Support Annexes, which provide credit lines for collateral posting thus alleviating possible liquidity needs under the instruments and protect the Group from potential non-performance risk by its counterparties.

The Group's derivatives that hedge cash flows from the sales of crude oil for periods through December 31, 2022 are accounted for as non-hedge derivatives and therefore all changes in the fair values of these derivative contracts are recognized immediately as gains or losses in the results of the periods in which they occur.

The Group's derivatives that hedge cash flows from the sales of crude oil for periods from January 1, 2023 onwards are designated and qualify as cash flow hedges. The effective portion of changes in the fair values of these derivative contracts are recognized in Other Reserve within Equity. The gain or loss relating to the ineffective portion, if any, is recognized immediately as gains or losses in the results of the periods in which they occur. The amount accumulated in Other Reserves is reclassified to profit or loss as a reclassification adjustment in the same period or periods during which the hedged cash flows affect profit or loss.

The following table presents the Group's production hedged during the year ended December 31, 2022 and for the following periods as a consequence of the derivative contracts in force as of December 31, 2022:

Period	Reference	Type	Volume bbl/d	Weighted average price US$/bbl
ACCOUNTED FOR AS NON-HEDGE DERIVATIVES				
January 1, 2022 - March 31, 2022	ICE BRENT	Zero Premium Collars	14,500	49.10 Put 74.81 Call
April 1, 2022 - June 30, 2022	ICE BRENT	Zero Premium Collars	12,500	53.35 Put 79.38 Call
July 1, 2022 - September 30, 2022	ICE BRENT	Zero Premium Collars	13,000	58.63 Put 86.50 Call
October 1, 2022 - December 31, 2022	ICE BRENT	Zero Premium Collars	12,000	60.63 Put 92.55 Call
ACCOUNTED FOR AS CASH FLOW HEDGES				
January 1, 2023 - March 31, 2023	ICE BRENT	Zero Premium Collars	9,500	66.05 Put 112.59 Call
April 1, 2023 - June 30, 2023	ICE BRENT	Zero Premium Collars	8,500	69.12 Put 113.13 Call
July 1, 2023 - September 30, 2023	ICE BRENT	Zero Premium Collars	2,000	70.00 Put 101.13 Call

The table below summarizes the gain (loss) on the commodity risk management contracts:

	2022	2021	2020
Realized (loss) gain on commodity risk management contracts	(83,244)	(109,654)	21,059
Unrealized gain (loss) on commodity risk management contracts	13,023	463	(12,978)
	(70,221)	**(109,191)**	**8,081**

Note 9 Production and operating costs

Amounts in US$ '000	2022	2021	2020
Staff costs (Note 11)	13,114	16,655	14,689
Share-based payment (Note 11)	955	339	528
Royalties	63,298	40,000	20,891
Economic rights	188,989	73,023	14,984
Well and facilities maintenance	20,779	17,989	15,039
Operation and maintenance	6,545	7,826	7,491
Consumables	21,789	19,270	16,776
Equipment rental	7,580	8,127	8,570
Transportation costs	4,021	3,383	5,622
Field camp	4,070	4,386	3,130
Safety and insurance costs	3,745	4,216	4,505
Personnel transportation	2,480	2,397	2,115
Consultant fees	2,133	1,732	1,043
Gas plant costs	1,680	2,596	1,591
Non-operated blocks costs	12,650	4,941	3,442
Crude oil stock variation	(6,449)	1,271	(305)
Purchased crude oil	7,929	—	—
Other costs	4,471	4,639	4,961
	359,779	**212,790**	**125,072**

Note 10 Depreciation

Amounts in US$ '000	2022	2021	2020
Oil and gas properties	76,720	66,011	89,344
Production facilities and machinery	12,244	12,468	16,820
Furniture, equipment and vehicles	1,344	1,960	2,317
Buildings and improvements	672	700	490
Depreciation of property, plant and equipment [(a)]	**90,980**	**81,139**	**108,971**
Related to:			
Productive assets	88,964	78,479	106,164
Administrative assets	2,016	2,660	2,807
Depreciation total [(a)]	**90,980**	**81,139**	**108,971**

(a) Depreciation without considering capitalized costs for oil stock included in Inventories nor depreciation of right-of-use assets.

Note 11 Staff costs and Directors' Remuneration

	2022	2021	2020
Number of employees at year end [(a)]	482	463	437
Amounts in US$ '000			
Wages and salaries	38,354	42,236	49,338
Share-based payments (Note 31)	11,038	6,621	8,444
Social security charges	5,528	6,863	5,712
Director's fees and allowance	1,172	2,853	2,094
	56,092	**58,573**	**65,588**
Recognized as follows:			
Production and operating costs	14,069	16,994	15,217
Geological and geophysical expenses	7,490	6,219	12,893
Administrative expenses	34,533	35,360	37,478
	56,092	**58,573**	**65,588**
Board of Directors' and key managers' remuneration			
Salaries and fees	10,317	9,069	8,641
Share-based payments	8,728	5,759	7,170
Other benefits in kind	171	296	232
	19,216	**15,124**	**16,043**

(a) Unaudited.

Directors' Remuneration

	Executive Directors' Fees (in US$)	Non-Executive Directors' Fees (in US$)	Director Fees Paid in Shares (No. of Shares)	Cash Equivalent Total Remuneration (in US$)
James F. Park (a)	601,002	—	—	601,002
Andrés Ocampo (b)	—	—	—	—
Carlos Gulisano (c)	—	61,087	5,110	131,739
Robert Bedingfield (d)	—	30,000	14,803	235,000
Constantin Papadimitriou (e) (f)	—	167,500	7,335	267,500
Somit Varma (f) (g)	—	32,500	27,306	409,755
Sylvia Escovar Gomez (h)	—	35,000	15,510	249,755
Brian Maxted (i)	—	32,718	2,244	61,953
Carlos Macellari	—	30,462	2,244	60,082
Marcela Vaca (j)	—	14,130	1,084	28,260

(a) Chief Executive Officer until his resignation on June 30, 2022. As of July 1, 2022, Mr. Park signed a consulting agreement with the Company to act as CEO advisor and provide support and assistance in addition to his role as Vicechair, non-executive Director and Strategy and Risk Committee Chairman.

(b) As of July 1, 2022, Andrés Ocampo has a service contract to act as Chief Executive Officer, and he relinquished his fees as a member of the Board.

(c) Director until his resignation on July 15, 2022.

(d) Audit Committee Chairman.

(e) Compensation Committee Chairman.

(f) Constantin Papadimitriou and Somit Varma, as members of the Strategy and Risk Committee, instructed by the Board, were awarded additional fees on their work related to specific projects and activities. The additional fees are included in the table above.

(g) Nomination and Corporate Governance Committee Chairman.

(h) Independent Chair of the Board.

(i) Technical Committee Chairman.

(j) SPEED Committee Chairman.

Note 12 Geological and geophysical expenses

Amounts in US$ '000	2022	2021	2020
Staff costs (Note 11)	7,097	6,042	12,653
Share-based payment (Note 11)	393	177	240
Communication and IT costs	1,743	1,071	850
Consultant fees	917	854	545
Allocation to capitalized project	(416)	(953)	(102)
Other services	795	700	765
	10,529	**7,891**	**14,951**

Note 13 Administrative expenses

Amounts in US$ '000	2022	2021	2020
Staff costs (Note 11)	23,671	26,402	27,708
Share-based payment (Note 11)	9,690	6,105	7,676
Consultant fees	9,574	10,806	8,570
Safety and insurance costs	3,834	3,142	2,394
Travel expenses	2,336	719	939
Non-operated blocks expenses	1,390	799	319
Director's fees and allowance (Note 11)	1,172	2,853	2,094
Communication and IT costs	3,419	4,214	2,937
Allocation to joint operations	(9,642)	(8,574)	(6,720)
Other administrative expenses	4,580	362	4,398
	50,024	**46,828**	**50,315**

Note 14 Selling expenses

Amounts in US$ '000	2022	2021	2020
Transportation	4,881	4,233	4,787
Selling taxes and other	3,114	4,497	1,057
	7,995	**8,730**	**5,844**

Note 15 Financial results

Amounts in US$ '000	2022	2021	2020
Financial expenses			
Interest and amortization of debt issue costs	(36,360)	(44,713)	(48,779)
Borrowings cancellation costs	(5,141)	(6,308)	—
Bank charges and other financial results	(9,546)	(8,012)	(9,909)
Unwinding of long-term liabilities	(6,026)	(5,079)	(5,894)
	(57,073)	**(64,112)**	**(64,582)**
Financial income			
Interest received	3,180	1,652	3,166
	3,180	**1,652**	**3,166**
Foreign exchange gains and losses			
Foreign exchange gain (loss), net	19,725	5,049	(2,720)
Realized result on currency risk management contracts	—	—	(9,414)
Unrealized result on currency risk management contracts	—	—	(874)
	19,725	**5,049**	**(13,008)**
Total Financial results	**(34,168)**	**(57,411)**	**(74,424)**

Note 16 Tax reforms

Colombia

In November 2022, the Colombian Congress approved a Tax Reform ("Law 2277") which contemplates an increase in the effective tax rate and the government take for certain entities of the oil and gas industry.

The main impacts derived from the Law 2277 for GeoPark as part of the oil and gas industry include a provision that prevents the deduction of royalties for Corporate Income Tax ("CIT") calculation purposes. Royalties paid in cash are assessed at a commercial value net of production costs while, royalties paid in-kind are assessed at their production cost.

A second relevant provision included in the Law 2277 establishes a permanent surtax for companies developing crude oil extractive activities, ranging between 5% and 15%. The surtax triggers when the Brent price average during the fiscal year meets percentiles 30 and upwards of the Brent price average of the last 10 years (as shown in the table below regarding fiscal year 2023) and is calculated as additional percentage points of the CIT rate that is applicable to the taxable base determined on a regular basis for CIT purposes. Income derived from gas production is exempted of surtax.

2023 Surcharge Price Triggers	Surcharge rate
< US$ 65.28 /bbl	0%
US$ 65.28 to US$ 73.77 /bbl	5%
US$ 73.78 to US$ 78.69 /bbl	10%
> US$ 78.69 /bbl	15%

In addition to the aforementioned rules, the Law 2277 includes other measures such as the strike off of the straight-line amortization method for new exploratory assets which will pass to be calculated under the 'unit of production' method, and repeals the tax credit of 50% of the industry and commerce tax paid during the year, which will no longer be treated as a tax credit but as a common deduction. The tax rate for dividends tax increases to 20% as well as the rate for capital gains tax that increases to 15%.

The new tax provisions will go into effect in 2023 and do not affect current tax bases or tax rate for fiscal year 2022. Nevertheless, the surtax has been considered for deferred income tax purposes as of December 31, 2022.

Spain

As from December 2021, tax regulations turned a full income tax exemption on dividend and capital gains income into a 95% exemption.

Note 17 Income tax

Amounts in US$ '000	2022	2021	2020
Current income tax charge	(125,786)	(49,291)	(41,927)
Deferred income tax charge (Note 18)	(44,688)	(17,980)	(5,936)
	(170,474)	**(67,271)**	**(47,863)**

The tax on the Group's profit (loss) before tax differs from the theoretical amount that would arise using the weighted average tax rate applicable to profits of the consolidated entities as follows:

Amounts in US$ '000	2022	2021	2020
Profit (Loss) before tax	394,909	128,398	(185,087)
Tax losses from non-taxable jurisdictions	53,005	91,351	53,652
Taxable profit	**447,914**	**219,749**	**(131,435)**
Income tax calculated at domestic tax rates applicable to Profit in the respective countries	(157,315)	(71,086)	12,450
Tax losses where no deferred income tax benefit is recognized	(2,832)	(7,510)	(23,117)
Effect of currency translation on tax base	(10,797)	(10,354)	(923)
Effect of inflation adjustment for tax purposes	—	2,482	(867)
Changes in the income tax rate (Note 16)	(3,820)	(1,703)	(925)
Write-down of deferred income tax benefits previously recognized [(a)]	(2,938)	(7,261)	(32,565)
Previously unrecognized tax losses	9,067	9,593	—
Income tax on dividends [(b)]	(3,038)	—	—
Fiscal recognition of property, plant and equipment	—	8,919	—
Non-taxable results [(c)]	1,199	9,649	(1,916)
Income tax	**(170,474)**	**(67,271)**	**(47,863)**

(a) Includes write-down of the deferred income tax asset in Peru due to the decision to retire from the Morona Block (see Note 36.4.1) in 2020, and write-down of a portion of tax losses and other deferred income tax assets in Chile, Brazil and Argentina where there is insufficient evidence of future taxable profits to offset them, in accordance with the expected future cash-flows as of December 31, 2022, 2021 and 2020.

(b) Includes income tax payable in Spain due to dividends received from subsidiaries. See Note 16.

(c) Includes non-deductible expenses and non-taxable gains in each jurisdiction.

Under current Bermuda law, the Company is not required to pay any taxes in Bermuda on income or capital gains. The Company has received an undertaking from the Minister of Finance in Bermuda that, in the event of any taxes being imposed, they will be exempt from taxation in Bermuda until March 2035. Income tax rates in those countries where the Group operates (Colombia, Chile, Brazil and Ecuador) ranges from 15% to 50% (see Note 16). There are no income tax consequences attached to the payment of dividends by the Group to its shareholders.

The Group has tax losses available which can be utilized against future taxable profit in the following countries:

Amounts in US$ '000	2022	2021	2020
Colombia [(a)]	4,837	15,557	16,493
Chile [(a)]	323,929	285,456	403,258
Brazil [(a)]	26,736	26,781	32,452
Argentina [(b)]	24,065	35,773	20,734
Spain [(a)]	7,205	9,443	9,694
Total tax losses as of December 31	**386,772**	**373,010**	**482,631**

(a) Taxable losses have no expiration date.

(b) Tax losses accumulated as of December 31, 2022 are: US$ 994,000, US$ 4,757,000, US$ 3,285,000, US$ 10,496,000 and US$ 4,533,000 expiring in 2023, 2024, 2025, 2026 and 2027, respectively.

As of December 31, 2022, deferred income tax assets in respect of tax losses in Argentina and a portion of tax losses in Chile and Brazil have not been recognized as there is insufficient evidence of future taxable profits to offset them.

Note 18 Deferred income tax

The gross movement on the deferred income tax account is as follows:

Amounts in US$ '000	2022	2021
Deferred income tax as of January 1	(6,875)	10,978
Currency translation differences	383	127
Income statement charge	(44,688)	(17,980)
Deferred income tax as of December 31	**(51,180)**	**(6,875)**

The breakdown and movement of deferred income tax assets and liabilities as of December 31, 2022 and 2021 are as follows:

Amounts in US$ '000	At the beginning of year	Charged to net profit	Currency translation differences	At the end of year
Deferred income tax assets				
Difference in depreciation rates and other	(344)	4,720	383	4,759
Tax losses	14,416	(232)	—	14,184
Total 2022	**14,072**	**4,488**	**383**	**18,943**
Total 2021	**18,168**	**(4,223)**	**127**	**14,072**

Amounts in US$ '000	At the beginning of year	Charged to net profit	At the end of year
Deferred income tax liabilities			
Difference in depreciation rates and other	(20,947)	(49,176)	(70,123)
Total 2022	**(20,947)**	**(49,176)**	**(70,123)**
Total 2021	**(7,190)**	**(13,757)**	**(20,947)**

Note 19 Earnings per share

Amounts in US$ '000 except for shares	2022	2021	2020
Numerator: Profit (Loss) for the year	224,435	61,127	(232,950)
Denominator: Weighted average number of shares used in basic EPS	59,330,421	60,901,109	60,668,185
Earnings (Losses) after tax per share (US$) – basic	**3.78**	**1.00**	**(3.84)**

Amounts in US$ '000 except for shares	2022	2021	2020
Weighted average number of shares used in basic EPS	59,330,421	60,901,109	60,668,185
Effect of dilutive potential common shares (a)			
Stock awards at US$ 0.001	552,466	559,012	—
Weighted average number of common shares for the purposes of diluted earnings per shares	59,882,887	61,460,121	60,668,185
Earnings (Losses) after tax per share (US$) – diluted	**3.75**	**0.99**	**(3.84)**

(a) For the year ended December 31, 2020, the effect of the potential shares that could have a dilutive impact was considered antidilutive due to negative earnings.

Note 20 Property, plant and equipment

Amounts in US$'000	Oil & gas properties	Furniture, equipment and vehicles	Production facilities and machinery	Buildings and improvements	Construction in progress	Exploration and evaluation assets[a]	Total
Cost as of January 1, 2020	**830,937**	**19,549**	**172,507**	**11,770**	**69,587**	**48,036**	**1,152,386**
Additions	(2,863)[b]	1,180	—	422	55,267	18,429	72,435
Acquisitions (Note 36.1)	185,533	553	16,181	212	1,199	73,310	276,988
Currency translation differences	(14,399)	(194)	(1,036)	(59)	(47)	(401)	(16,136)
Disposals	—	(555)	—	(227)	(33)	—	(815)
Write-off / Impairment	(77,667)[c]	—	(11,357)[c]	—	(44,840)[c]	(52,652)[d]	(186,516)
Transfers	48,361	174	21,534	324	(62,285)	(8,108)	—
Assets held for sale (Note 36.2.2)	(1,285)	—	—	—	—	—	(1,285)
Cost as of December 31, 2020	**968,617**	**20,707**	**197,829**	**12,442**	**18,848**	**78,614**	**1,297,057**
Additions	(1,094)[b]	930	—	—	82,094	46,234	128,164
Currency translation differences	(3,284)	(43)	(246)	(16)	(18)	(30)	(3,637)
Disposals	—	(1,762)	(900)	(978)	(3,372)	(338)	(7,350)
Write-off / Impairment	(1,575)[c]	—	(2,759)[c]	—	—	(12,262)[e]	(16,596)
Transfers	68,315	58	13,305	391	(70,321)	(11,748)	—
Assets held for sale (Note 36.3.1)	(73,047)	(1,178)	(6,052)	(177)	(27)	—	(80,481)
Cost as of December 31, 2021	**957,932**	**18,712**	**201,177**	**11,662**	**27,204**	**100,470**	**1,317,157**
Additions	(7,558)[b]	1,620	6	(14)	107,171	67,889	169,114
Currency translation differences	2,921	37	232	6	18	19	3,233
Disposals	—	(1,290)	(26)	(774)	—	—	(2,090)
Write-off / Impairment	—	—	—	—	—	(25,789)[f]	(25,789)
Transfers	125,962	14	21,338	147	(117,913)	(29,548)	—
Cost as of December 31, 2022	**1,079,257**	**19,093**	**222,727**	**11,027**	**16,480**	**113,041**	**1,461,625**
Depreciation and write-down as of January 1, 2020	**(467,806)**	**(15,149)**	**(95,047)**	**(6,596)**	**—**	**—**	**(584,598)**
Depreciation	(89,344)	(2,317)	(16,820)	(490)	—	—	(108,971)
Disposals	—	326	—	72	—	—	398
Currency translation differences	8,572	155	1,880	39	—	—	10,646
Assets held for sale (Note 36.2.2)	133	—	—	—	—	—	133
Depreciation and write-down as of December 31, 2020	**(548,445)**	**(16,985)**	**(109,987)**	**(6,975)**	**—**	**—**	**(682,392)**
Depreciation	(66,011)	(1,960)	(12,468)	(700)	—	—	(81,139)
Disposals	—	1,325	900	838	—	—	3,063
Currency translation differences	2,219	37	246	16	—	—	2,518
Assets held for sale (Note 36.3.1)	49,080	915	4,692	153	—	—	54,840
Depreciation and write-down as of December 31, 2021	**(563,157)**	**(16,668)**	**(116,617)**	**(6,668)**	**—**	**—**	**(703,110)**
Depreciation	(76,720)	(1,344)	(12,244)	(672)	—	—	(90,980)
Disposals	—	1,246	19	752	—	—	2,017
Currency translation differences	(2,403)	(33)	(231)	(6)	—	—	(2,673)
Depreciation and write-down as of December 31, 2022	**(642,280)**	**(16,799)**	**(129,073)**	**(6,594)**	**—**	**—**	**(794,746)**
Carrying amount as of December 31, 2020	**420,172**	**3,722**	**87,842**	**5,467**	**18,848**	**78,614**	**614,665**
Carrying amount as of December 31, 2021	**394,775**	**2,044**	**84,560**	**4,994**	**27,204**	**100,470**	**614,047**
Carrying amount as of December 31, 2022	**436,977**	**2,294**	**93,654**	**4,433**	**16,480**	**113,041**	**666,879**

(a) Exploration wells movement and balances are shown in the table below; mining property associated with unproved reserves and resources, seismic and other exploratory assets amount to US$ 96,041,000 (US$ 90,166,000 in 2021 and US$ 75,485,000 in 2020).

Amounts in US$ '000	Total
Exploration wells as of December 31, 2020	**3,129**
Additions	25,795
Write-offs	(6,814)
Transfers	(11,806)
Exploration wells as of December 31, 2021	**10,304**
Additions	56,491
Write-offs	(21,460)
Transfers	(28,335)
Exploration wells as of December 31, 2022	**17,000**

As of December 31, 2022, there were six exploratory wells that have been capitalized for a period less than a year amounting to US$ 17,000,000.

(b) Corresponds to the effect of change in estimate of assets retirement obligations.

(c) See Note 37.

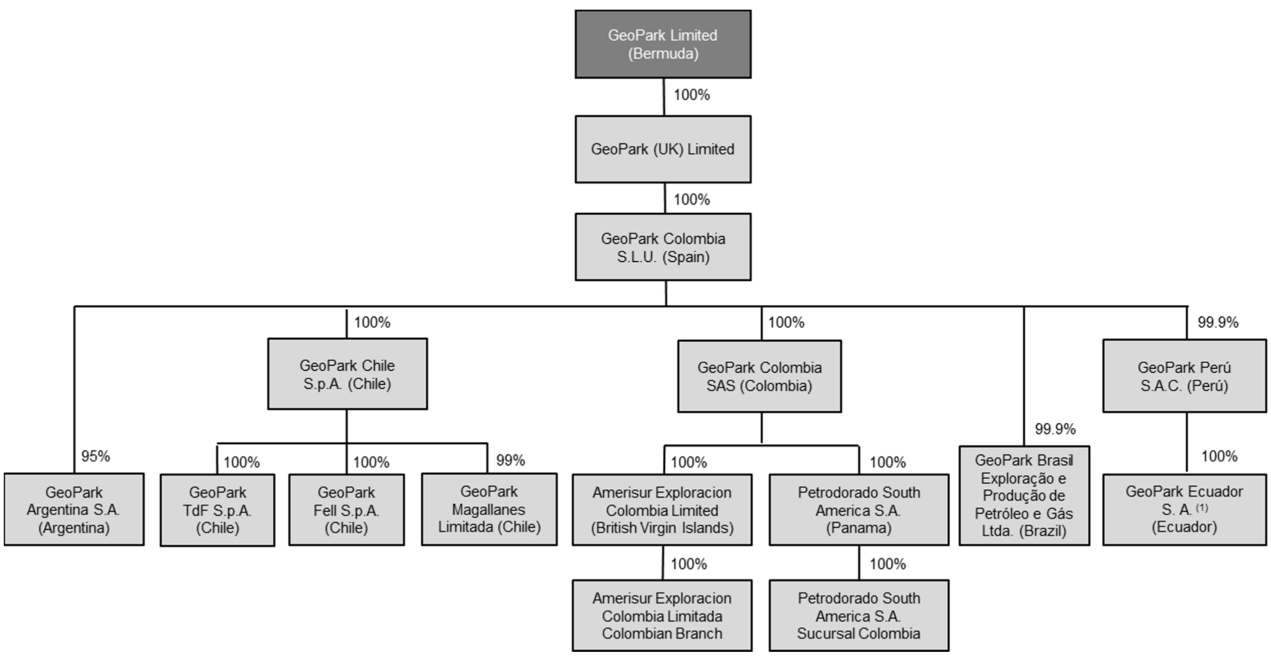
(d) Corresponds to three unsuccessful exploratory wells drilled in the Isla Norte Block (Chile), Llanos 94 Block (Colombia) and CPO-5 Block (Colombia), and exploration costs incurred in previous years in the POT-T-619 Block (Brazil) for which no additional work would be performed. The charge also includes the write-off of seismic and other exploration costs incurred in previous years in the Fell, Campanario, Flamenco and Isla Norte Blocks (Chile), where, as a result of the drilling campaign performed during 2020 and in accordance with the Group's accounting policy, it cannot be clearly demonstrated that the carrying value of the investment is recoverable.

(e) Corresponds to two unsuccessful exploratory wells drilled in the Llanos 32 Block (Colombia), other exploration costs incurred in the Fell Block (Chile), an exploratory well drilled in previous years in the CPO-5 Block (Colombia) and other exploration costs incurred in previous years in the PUT-30 Block (Colombia) for which no additional work would be performed.

(f) Corresponds to exploration costs incurred in previous years in the Tacacho and Terecay Blocks (Colombia) for which no additional work would be performed, four exploratory wells drilled in the CPO-5, Platanillo, Llanos 34 and Llanos 94 Blocks (Colombia), and certain exploration costs incurred in the Espejo Block (Ecuador).

Note 21 Subsidiary undertakings

The following chart illustrates main companies of the Group structure as of December 31, 2022:



(1) GeoPark Ecuador S.A. holds 50% working interest in the consortiums that operate the Espejo and Perico Blocks.

During the year ended December 31, 2022, the following changes to the Group structure have taken place:

- GeoPark Colombia S.A.S. acquired the shares of GeoPark Colombia E&P previously owned by GeoPark Latin America S.L.U.
- GeoPark Colombia S.A.S. was assigned a 50% non-operated working interest in the CPO-4-1 Block.

- The Ecuadorean Branch named “GeoPark Perú S.A.C. Sucursal Ecuador” was transformed into a local company in Ecuador named “GeoPark Ecuador S.A.”
- The Spanish subsidiaries finalized a merger process by which GeoPark Latin America S.L.U. merged with and into GeoPark Colombia S.L.U., with the latter being the surviving company.

In January 2023, the merger process between GeoPark Colombia S.A.S., GeoPark Colombia E&P S.A. and Petrodorado South America S.A., with GeoPark Colombia S.A.S. being the surviving company, was approved by the relevant Colombian authorities and the merger became effective as of its registration in the Public Registry of the Chamber of Commerce of Bogota on January 27, 2023.

Details of all the subsidiaries of the Group as of December 31, 2022 are set out below:

	Name and registered office	**Ownership interest**
Subsidiaries	GeoPark Argentina S.A. (Argentina)	100% (a)
	GeoPark Brasil Exploração e Produção de Petróleo e Gás Ltda. (Brazil)	100% (a)
	GeoPark Chile S.p.A. (Chile)	100% (a)
	GeoPark Fell S.p.A. (Chile)	100% (a)
	GeoPark Magallanes Limitada (Chile)	100% (a)
	GeoPark TdF S.p.A. (Chile)	100% (a)
	GeoPark Colombia S.A.S. (Colombia)	100% (a)
	GeoPark Colombia S.L.U. (Spain)	100% (a)
	GeoPark Perú S.A.C. (Peru)	100% (a)
	GeoPark Colombia E&P S.A. (Panama)	100% (a)
	GeoPark Colombia E&P Sucursal Colombia (Colombia)	100% (a)
	GeoPark Mexico S.A.P.I. de C.V. (Mexico)	100% (a) (b)
	GeoPark E&P S.A.P.I. de C.V. (Mexico)	100% (a) (b)
	GeoPark Ecuador S.A. (Ecuador)	100% (a)
	GeoPark (UK) Limited (United Kingdom)	100%
	Amerisur Resources Limited (United Kingdom)	100% (a)
	Amerisur Exploración Colombia Limited (British Virgin Islands)	100% (a)
	Amerisur Exploración Colombia Limited Sucursal Colombia (Colombia)	100% (a)
	Yarumal S.A.S. (Colombia)	100% (a) (b)
	Petrodorado South America S.A. (Panama)	100% (a)
	Petrodorado South America S.A. Sucursal Colombia (Colombia)	100% (a)
	Fenix Oil & Gas Limited (British Virgin Islands)	100% (a) (b)
	Fenix Oil & Gas Limited Sucursal Colombia (Colombia)	100% (a) (b)
	Amerisurexplor Ecuador S.A. (Ecuador)	100% (a) (b)
	Amerisur S.A. (Paraguay)	100% (a) (b)
	Market Access LLP (United States)	9%

(a) Indirectly owned.
(b) Dormant companies.

Details of the joint operations of the Group as of December 31, 2022 are set out below:

	Name and registered office	Ownership interest
Joint operations	Flamenco Block (Chile)	50% (a)
	Campanario Block (Chile)	50% (a)
	Isla Norte Block (Chile)	60% (a)
	Llanos 34 Block (Colombia)	45% (a)
	Llanos 32 Block (Colombia)	12.5%
	Puelen Block (Argentina)	18% (b)
	Los Parlamentos (Argentina)	50%
	Manati Field (Brazil)	10%
	POT-T-785 Block (Brazil)	70% (a)
	Espejo Block (Ecuador)	50% (a)
	Perico Block (Ecuador)	50%
	Llanos 86 Block (Colombia)	50% (a)
	Llanos 87 Block (Colombia)	50% (a)
	Llanos 104 Block (Colombia)	50% (a)
	Llanos 123 Block (Colombia)	50% (a)
	Llanos 124 Block (Colombia)	50% (a)
	CPO-5 Block (Colombia)	30%
	Mecaya Block (Colombia)	50% (a)
	PUT-8 Block (Colombia)	50% (a)
	PUT-9 Block (Colombia)	50% (a)
	Tacacho Block (Colombia)	50% (a) (b)
	Terecay Block (Colombia)	50% (a) (b)
	Llanos 94 Block (Colombia)	50%
	PUT-36 Block (Colombia)	50% (a)
	CPO-4-1 Block (Colombia)	50%

(a) GeoPark is the operator.
(b) In process of relinquishment.

Note 22 Prepayments and other receivables

Amounts in US$ '000	2022	2021
V.A.T.	1,826	1,711
Income tax payments in advance	3,156	3,227
Other prepaid taxes	37	996
To be recovered from co-venturers (Note 34)	8,750	4,680
Prepayments and other receivables	8,458	12,184
	22,227	**22,798**
Classified as follows:		
Current	22,106	22,650
Non-current	121	148
	22,227	**22,798**

Movements on the Group provision for impairment are as follows:

Amounts in US$ '000	2022	2021
At January 1	7	144
Additions	10	—
Foreign exchange loss	(3)	(13)
Uses	—	(124)
	14	**7**

Note 23 Inventories

Amounts in US$ '000	2022	2021
Crude oil	12,630	5,419
Materials and spares	1,804	5,496
	14,434	**10,915**

Note 24 Trade receivables

Amounts in US$ '000	2022	2021
Trade receivables	71,794	70,531
	71,794	**70,531**

As of December 31, 2022 and 2021, there are no balances that were aged by more than 3 months. Trade receivables that are aged by less than three months are not considered impaired.

The credit period for trade receivables is 30 days. The maximum exposure to credit risk at the reporting date is the carrying value of each class of receivable. The Group does not hold any collateral as security related to trade receivables.

The carrying value of trade receivables is considered to represent a reasonable approximation of its fair value due to their short-term nature.

Note 25 Financial instruments by category

	Assets as per statement of financial position	
Amounts in US$ '000	**2022**	**2021**
Financial assets at fair value through profit or loss		
Derivative financial instrument assets	967	126
Cash and cash equivalents	242	427
	1,209	**553**
Other financial assets at amortized cost		
Trade receivables	71,794	70,531
To be recovered from co-venturers (Note 34)	8,750	4,680
Other financial assets [(a)]	12,877	14,747
Cash and cash equivalents	128,601	100,177
	222,022	**190,135**
Total financial assets	**223,231**	**190,688**

(a) Non-current other financial assets relate to restricted deposits made for environmental obligations according to Brazilian government regulations. Current other financial assets correspond to short-term investments with original maturities up to twelve months and over three months.

Amounts in US$ '000	Liabilities as per statement of financial position 2022	2021
Liabilities at fair value through profit and loss		
Derivative financial instrument liabilities	19	20,757
	19	**20,757**
Other financial liabilities at amortized cost		
Trade payables	102,125	86,672
To be paid to co-venturers (Note 34)	2,815	953
Lease liabilities	32,051	20,744
Borrowings	497,642	674,092
	634,633	**782,461**
Total financial liabilities	**634,652**	**803,218**

25.1 Credit quality of financial assets

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit ratings (if available) or to historical information about counterparty default rates:

Amounts in US$ '000	2022	2021
Trade receivables		
Counterparties with an external credit rating (Moody's, S&P, Fitch)		
Aa2	—	7,132
Aa3	2,013	—
A3	1,557	—
Baa1	99	—
Baa3	198	24,163
Ba1	23,755	4,984
Ba3	2,745	—
B2	4,085	70
Counterparties without an external credit rating		
Group 1 [(a)]	37,342	34,182
Total trade receivables	**71,794**	**70,531**

[(a)] Group 1 – existing customers (more than 6 months) with no defaults in the past.

All trade receivables are denominated in US Dollars, except in Brazil where they are denominated in Brazilian Real.

Cash at bank and other financial assets [a]

Amounts in US$ '000	2022	2021
Counterparties with an external credit rating (Moody's, S&P, Fitch, BRC Investor Services)		
Aaa	—	3,529
Aa3	10,362	8
A1	96,077	—
A2	57	53,114
A3	10,389	27,257
Baa1	39	1,605
Baa2	7,030	3,708
Baa3	1,352	—
Ba1	64	67
Ba2	268	21
Ba3	3,066	5,117
B3	51	—
Counterparties without an external credit rating	12,953	20,908
Total	**141,708**	**115,334**

[a] The remaining balance sheet item 'cash and cash equivalents' corresponds to cash on hand amounting to US$ 12,000 (US$ 17,000 in 2021).

25.2 Financial liabilities- contractual undiscounted cash flows

The table below analyses the Group's financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet to the contractual maturity date. The amounts disclosed in the table are the contractual undiscounted cash flows.

Amounts in US$ '000	Less than 1 year	Between 1 and 2 years	Between 2 and 5 years	Over 5 years
As of December 31, 2022				
Borrowings	27,500	27,500	568,750	—
Lease liabilities	10,939	5,653	11,209	25,012
Trade payables	102,125	—	—	—
To be paid to co-venturers (Note 34)	2,815	—	—	—
	143,379	**33,153**	**579,959**	**25,012**
As of December 31, 2021				
Borrowings	40,943	38,550	263,550	513,750
Lease liabilities	9,230	6,558	5,820	2,871
Trade payables	85,132	1,540	—	—
To be paid to co-venturers (Note 34)	953	—	—	—
	136,258	**46,648**	**269,370**	**516,621**

25.3 Fair value measurement of financial instruments

Accounting policies for financial instruments have been applied to classify as either: amortized cost, financial assets at fair value through profit or loss and fair value through other comprehensive income. For financial instruments that are measured in the statement of financial position at fair value, IFRS 13 requires a disclosure of fair value measurements by level according to the following fair value measurement hierarchy:

Level 1 - Quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 - Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (that is, as prices) or indirectly (that is, derived from prices).

Level 3 - Inputs for the asset or liability that are not based on observable market data (that is, unobservable inputs).

25.3.1 Fair value hierarchy

The following table presents the Group's financial assets and financial liabilities measured and recognized at fair value as of December 31, 2022 and 2021 on a recurring basis:

Amounts in US$ '000	Level 1	Level 2	As of December 31, 2022
Assets			
Cash and cash equivalents			
Money market funds	242	—	242
Derivative financial instrument assets			
Commodity risk management contracts	—	967	967
Total Assets	**242**	**967**	**1,209**
Liabilities			
Derivative financial instrument liabilities			
Commodity risk management contracts	—	19	19
Total Liabilities	**—**	**19**	**19**

Amounts in US$ '000	Level 1	Level 2	As of December 31, 2021
Assets			
Cash and cash equivalents			
Money market funds	427	—	427
Derivative financial instrument assets			
Commodity risk management contracts	—	126	126
Total Assets	**427**	**126**	**553**
Liabilities			
Derivative financial instrument liabilities			
Commodity risk management contracts	—	20,757	20,757
Total Liabilities	**—**	**20,757**	**20,757**

There were no transfers between Level 2 and 3 during the period.

The Group did not measure any financial assets or financial liabilities at fair value on a non-recurring basis as of December 31, 2022.

25.3.2 Valuation techniques used to determine fair values

Specific valuation techniques used to value financial instruments include:

- The use of quoted market prices or dealer quotes for similar instruments.
- The mark-to-market fair value of the Group's outstanding derivative instruments is based on independently provided market rates and determined using standard valuation techniques, including the impact of counterparty credit risk and are within level 2 of the fair value hierarchy.
- The fair value of the remaining financial instruments is determined using discounted cash flow analysis. All of the resulting fair value estimates are included in level 2.

25.3.3 Fair values of other financial instruments (unrecognized)

The Group also has a number of financial instruments which are not measured at fair value in the balance sheet. For the majority of these instruments, the fair values are not materially different to their carrying amounts, since the interest receivable/payable is either close to current market rates or the instruments are short-term in nature.

Borrowings are comprised primarily of fixed rate debt and variable rate debt with a short-term portion where interest has already been fixed. They are classified under other financial liabilities and measured at their amortized cost.

The fair value of these financial instruments as of December 31, 2022 amounts to US$ 431,660,000 (US$ 661,404,000 in 2021). The fair values are based on market price for the Notes and cash flows discounted for other borrowings using a rate based on the borrowing rate and are within level 1 and level 2 of the fair value hierarchy, respectively.

Note 26 Equity

26.1 Share capital and Share premium

Issued share capital	2022	2021
Common stock (amounts in US$ '000)	**58**	**60**
The share capital is distributed as follows:		
Common shares, of nominal US$ 0.001	57,621,998	60,238,026
Total common shares in issue	**57,621,998**	**60,238,026**
Authorized share capital		
US$ per share	0.001	0.001
Number of common shares (US$ 0.001 each)	5,171,949,000	5,171,949,000
Amount in US$	5,171,949	5,171,949

Details regarding the share capital of the Company are set out below.

26.1.1 Common shares

As of December 31, 2022, the outstanding common shares confer the following rights on the holder:

- the right to one vote per share
- ranking *pari passu*, the right to any dividend declared and payable on common shares

GeoPark common shares history	Month	Shares issued (millions)	Shares closing (millions)	US$(`000) Closing
Shares outstanding at the end of 2020			**61.0**	**61**
Stock awards	May 2021	0.2	61.2	61
Buyback program	Jun 2021	(0.1)	61.1	61
Buyback program	Sep 2021	(0.4)	60.7	61
Buyback program	Dec 2021	(0.5)	60.2	60
Shares outstanding at the end of 2021			**60.2**	**60**
Buyback program	Mar 2022	(0.2)	60.0	60
Buyback program	Jun 2022	(0.5)	59.5	60
Stock awards	Jul 2022	0.1	59.6	60
Buyback program	Sep 2022	(1.1)	58.5	59
Buyback program	Dec 2022	(0.9)	57.6	58
Shares outstanding at the end of 2022			**57.6**	**58**

26.1.2 Stock Award Program and Other Share Based Payments

Non-Executive Directors Fees

During 2022, the Company issued 75,636 (64,269 in 2021 and 60,204 in 2020) shares to Non-Executive Directors in accordance with contracts as compensation, generating a share premium of US$ 1,040,000 (US$ 861,000 in 2021 and US$ 665,000 in 2020). The amount of shares issued is determined considering the contractual compensation and the fair value of the shares for each relevant period.

Stock Award Program and Other Share Based Payments

On July 15, 2022, 52,058 common shares were issued as part of the founding executive employment agreement in place with the former Chief Executive Officer (104,439 in 2021), generating a share premium of US$ 800,000 (US$ 800,000 in 2021).

On November 12, 2020, 499,614 common shares were allotted to the trustee of the Employee Beneficiary Trust ("EBT") to be assigned to certain employees as part of their 2019 bonus compensation, generating a share capital and share premium of US$ 1,000 and US$ 4,351,000, respectively.

On January 2, 2020 and 2019 (50% each year, as set up in the plan), the vested Value Creation Plan ("VCP") awards, representing 2,976,781 common shares, was issued to key management (including 878,150 common shares issued to Directors involved in the performance of the Company), generating a share premium of US$ 4,668,000 (50% each year).

26.1.3 Buyback Program

On February 10, 2020, the Company's board of directors approved a program to repurchase up to 10% of its shares outstanding or approximately 5,930,000 shares. The repurchase program began on February 11, 2020 and was suspended in April 2020 as part of the revised work program for 2020 because of the COVID-19 pandemic and the oil price crisis. During 2020, the Company purchased 316,445 common shares for a total amount of US$ 3,071,000. These transactions had no impact on the Group's results.

On November 4, 2020, the Company's board of directors approved a new program to repurchase up to 10% of its shares outstanding or approximately 6,062,000 shares. The repurchase program began on November 5, 2020 and was set to expire on November 15, 2021. On November 10, 2021, the Company's board of directors approved the renewal of this repurchase program until November 10, 2022. Finally, on November 9, 2022, the Company's board of directors approved a new renewal of the program to repurchase up to 10% of our shares outstanding or approximately 5,854,285 shares until December 31, 2023. During 2022, the Company purchased 2,743,722 common shares (960,454 in 2021 and 101,986 in 2020) for a total amount of US$ 36,265,000 (US$ 11,841,000 in 2021 and US$ 938,000 in 2020). These transactions had no impact on the Group's results.

26.2 Cash distributions

On November 6, 2019, the Company's board of directors declared the initiation of quarterly cash distribution.

The following table summarizes the cash distributions for each of the years presented:

Date of declaration	Date of distribution	US$ per share	Total amount in US$ '000
March 4, 2020 [(a)]	April 8, 2020	0.0413	2,343
November 4, 2020 [(a)]	December 9, 2020	0.0206	1,258
November 4, 2020 [(a)]	December 9, 2020	0.0206	1,258
Cash distributions for the year ended December 31, 2020			**4,859**
March 10, 2021	April 13, 2021	0.0205	1,133
May 5, 2021	May 28, 2021	0.0205	1,220
August 4, 2021	August 31, 2021	0.0410	2,442
November 10, 2021	December 7, 2021	0.0410	2,429
Cash distributions for the year ended December 31, 2021			**7,224**
March 9, 2022	March 31, 2022	0.0820	4,847
May 11, 2022	June 10, 2022	0.0820	4,809
August 10, 2022	September 8, 2022	0.1270	7,345
November 9, 2022	December 7, 2022	0.1270	7,281
Cash distributions for the year ended December 31, 2022			**24,282**

(a) The quarterly cash distributions were temporary suspended in April 2020 as part of the revised work program for 2020 due to the COVID-19 pandemic and the oil price crisis. On November 4, 2020, the Company's board of directors declared an extraordinary cash distribution and also resumed the quarterly cash distributions.

These distributions are deducted from Other Reserve.

26.3 Stock distribution

On February 10, 2020, the Company's board of directors declared a special stock distribution of 0.004 shares per share. Consequently, on March 11, 2020, 242,650 common shares were distributed to the shareholders of record at the close of business on February 25, 2020.

Note 27 Borrowings

Amounts in US$ '000	2022	2021
Outstanding amounts as of December 31		
2024 Notes	—	171,880
2027 Notes	497,642	499,893
Banco Santander	—	2,319
	497,642	**674,092**
Classified as follows:		
Current	12,528	17,916
Non-current	485,114	656,176

On September 21, 2017, the Company successfully placed US$ 425,000,000 aggregate principal amount of 6.500% Senior Secured Notes due 2024 (the "2024 Notes"), which were offered to qualified institutional buyers in accordance with Rule 144A under the United States Securities Act (the "Securities Act"), and outside the United States to non-U.S. persons in accordance with Regulation S under the Securities Act. The 2024 Notes carry a coupon of 6.50% per annum. The debt issuance cost for this transaction amounted to US$ 6,683,000 (debt issuance effective rate: 6.90%).

On January 17, 2020, the Company successfully placed US$ 350,000,000 aggregate principal amount of 5.500% Senior Secured Notes due 2027 (the "2027 Notes"), which were offered in a private placement to qualified institutional buyers in accordance with Rule 144A under the Securities Act, and outside the United States to non U.S. persons in accordance with Regulation S under the Securities Act. The 2027 Notes were priced at 99.285% and carry a coupon of 5.50% per annum (yield 5.625% per annum). The debt issuance cost for this transaction amounted to US$ 5,004,000 (debt issuance effective rate: 5.88%). Final maturity of the 2027 Notes will be January 17, 2027.

In April 2021, the Company executed a series of transactions that included a successful tender to purchase US$ 255,000,000 of the 2024 Notes that was funded with a combination of cash in hand and a US$ 150,000,000 aggregate principal amount new issuance from the reopening of the 2027 Notes. The new notes offering and the tender offer closed on April 23, 2021, and April 26, 2021, respectively.

The tender total consideration included the tender offer consideration of US$ 1,000 for each US$ 1,000 principal amount of the 2024 Notes plus the early tender payment of US$ 50 for each US$ 1,000 principal amount of the 2024 Notes. The tender also included a consent solicitation to align the covenants of the 2024 Notes to those of the 2027 Notes.

The reopening of the 2027 Notes was priced above par at 101.875%, representing a yield to maturity of 5.117%. The debt issuance cost for this transaction amounted to US$ 2,019,000. The 2027 Notes were offered in a private placement to qualified institutional buyers in accordance with Rule 144A under the Securities Act, and outside the United States to non-U.S. persons in accordance with Regulation S under the Securities Act. The 2027 Notes are fully and unconditionally guaranteed jointly and severally by two principal subsidiaries of the Company.

Between March and July 2022, the Company continued its deleveraging process, by repurchasing and cancelling, with the Trustee, a total nominal amount of US$ 102,876,000 of its 2024 Notes. Of this total amount, US$ 57,876,000 were repurchased in open market transactions at prices below the call option level and US$ 45,000,000 were redeemed at a redemption price stated in the indenture governing the 2024 Notes. On September 21, 2022, GeoPark fully repaid its 2024 Notes by redeeming the remaining aggregate principal amount of US$ 67,124,000. Pursuant to the terms of the indenture governing the 2024 Notes, the Notes were redeemed at a redemption price equal to 101.625% of the principal amount of the Notes redeemed, plus accrued and unpaid interests. The difference between the carrying amount of debt that was repurchased or redeemed and the consideration paid was recognized within financial expenses in the Consolidated Statement of Income.

The indenture governing the 2027 Notes includes incurrence test covenants that provide, among other things, that the Net Debt to Adjusted EBITDA ratio should not exceed 3.25 times and the Adjusted EBITDA to Interest ratio should exceed 2.5 times. Failure to comply with the incurrence test covenants does not trigger an event of default. However, this situation may limit the Company's capacity to incur additional indebtedness, as specified in the indentures governing the Notes. Incurrence covenants, as opposed to maintenance covenants, must be tested by the Company before incurring additional debt or performing certain corporate actions including but not limited to dividend payments, restricted payments and others. As of the date of these Consolidated Financial Statements, the Company is in compliance of all the indentures' provisions and covenants.

On June 17, 2022, the Company received requisite consents from holders of the 2027 Notes for certain amendments to the indenture governing the 2027 Notes. The amendments intended to (i) address the impact of adverse market conditions and related drop in the price of crude oil during 2020 on the Company's results, which in turn negatively impacted the restricted payments builder basket, and (ii) increase and reset the general restricted payments basket in the indenture to provide the Company additional restricted payments capacity, giving the Company additional financial flexibility. Consequently, on June 27, 2022, the Company paid a consent fee equal to $10.00 per $1,000 to holders of the 2027 Notes that delivered their consents for the abovementioned amendments to the indenture governing the 2027 Notes. The consent fee and other related fees were deducted from the carrying value of the 2027 Notes and will be amortized over its term.

In October 2018, GeoPark Brasil Exploração e Produção de Petróleo e Gás Ltda. ("GeoPark Brazil") executed a loan agreement with Banco Santander for Brazilian Real 77,640,000 (equivalent to US$ 20,000,000 at the moment of the loan execution) to repay an existing US$-denominated intercompany loan. In September 2020, GeoPark Brazil executed the refinancing of the outstanding principal with Banco Santander for Brazilian Real 19,410,000 (equivalent to US$ 3,441,000 at the moment of the refinancing execution). The interest rate was CDI plus 3.55% per annum. "CDI" (Interbank certificate of deposit) represents the average rate of all inter-bank overnight transactions in Brazil. Interests were paid on a monthly basis, and principal was paid semi-annually in three equal instalments. The loan was fully repaid in October 2022.

As of the date of these Consolidated Financial Statements, the Group has available credit lines for US$ 111,198,000.

Note 28 Leases

The Consolidated Statement of Financial Position shows the following amounts relating to leases:

Amounts in US$ '000	2022	2021
Right of use assets		
Production, facilities and machinery	32,034	15,175
Buildings and improvements	4,977	5,839
	37,011	**21,014**
Lease liabilities		
Current	10,000	8,231
Non-current	22,051	12,513
	32,051	**20,744**

The Consolidated Statement of Income shows the following amounts relating to leases:

Amounts in US$ '000	2022	2021	2020
Depreciation charge of Right of use assets			
Production, facilities and machinery	(6,057)	(5,526)	(6,472)
Buildings and improvements	(988)	(1,136)	(1,600)
	(7,045)	**(6,662)**	**(8,072)**
Unwinding of long-term liabilities (included in Financial results)	(2,838)	(1,453)	(1,247)
Expenses related to short-term leases (included in Production and operating cost and Administrative expenses)	(2,614)	(1,101)	(1,317)
Expenses related to low-value leases (included in Administrative expenses)	(708)	(906)	(736)

The table below summarizes the amounts of Right-of-use assets recognized and the movements during the reporting years:

Amounts in US$'000	2022	2021
Right-of-use assets as of January 1	21,014	21,402
Additions / changes in estimates	22,462	5,288
Foreign currency translation	580	986
Depreciation	(7,045)	(6,662)
Right-of-use assets as of December 31	**37,011**	**21,014**

The table below summarizes the amounts of Lease liabilities recognized and the movements during the reporting years:

Amounts in US$'000	2022	2021
Lease liabilities as of January 1	20,744	22,347
Additions / changes in estimates	22,462	5,288
Exchange difference	(6,426)	(365)
Foreign currency translation	284	(461)
Unwinding of discount	2,838	1,453
Lease payments	(7,851)	(7,518)
Lease liabilities as of December 31	**32,051**	**20,744**

Note 29 Provisions and other long-term liabilities

Amounts in US$ '000	Asset retirement obligation	Deferred Income	Other	Total
As of January 1, 2021	**64,040**	**3,828**	**14,502**	**82,370**
Addition to provision / changes in estimates	(651)	(46)	59	(638)
Exchange difference	(668)	(228)	(1,079)	(1,975)
Foreign currency translation	(651)	—	(2)	(653)
Amortization	—	(223)	—	(223)
Unwinding of discount	3,140	—	486	3,626
Amounts used during the year	(170)	—	(291)	(461)
Liabilities associated with assets held for sale	(19,198)	—	—	(19,198)
As of December 31, 2021	**45,842**	**3,331**	**13,675**	**62,848**
Addition to provision / changes in estimates	(4,942)	—	(2,670)	(7,612)
Exchange difference	(669)	(167)	(1,147)	(1,983)
Foreign currency translation	(577)	—	14	(563)
Amortization	—	(2,407)	—	(2,407)
Unwinding of discount	2,641	—	547	3,188
Amounts used during the year	(1,392)	—	(132)	(1,524)
As of December 31, 2022	**40,903**	**757**	**10,287**	**51,947**

The provision for asset retirement obligation relates to the estimation of future disbursements related to the abandonment and decommissioning of oil and gas wells (see Note 4).

Deferred income relates to government grants and other contributions relating to the purchase of property, plant and equipment in Colombia. The amortization is in line with the related assets.

Other includes the provision for an environmental contingency in the United Kingdom and other environmental obligations in Colombia and Peru.

Environmental contingency in the United Kingdom

On January 8, 2020, Amerisur received a copy of a claim form issued in the High Court of England and Wales (the "Court") by Leigh Day solicitors on behalf of a group of claimants (the "Claimants") described as members of a farming community in the department of Putumayo in Colombia. The claim stated that the Claimants seek compensation for economic and non-economic damages said to be caused by alleged environmental contamination and pollution caused by Amerisur's operations in the region. Amerisur stated that the accusations of environmental damage referenced in the claim were being investigated by Colombian authorities and to-date had been deemed to be without merit. Following court hearings held in January and February 2020, an interim freezing order was imposed on Amerisur for an amount of GBP 4,465,600 of its assets located in the United Kingdom. On November 10, 2020, the freezing order was discharged by agreement between the parties as Amerisur provided alternative security in the form of a letter of credit from an international bank in the UK.

On January 12, 2021 a hearing was held, where the Court ordered the Claimants to serve the Group Particulars of Claim (the "GPoC") by February 26, 2021. During April and May 2021, the general pollution claims were struck out by the Court leaving only the claims arising from the attack on the oil-trucks on 2015. Amerisur presented its defence to the GPoC on May 21, 2021. A case management conference was held on July 7, 2021, after which the Court ordered on July 15, 2021 among others: i) to schedule a preliminary issues trial on two Colombian law issues, namely, limitation period for bringing the claims and limitation of parent company liability; and ii) to schedule a costs management conference. The costs management conference was held on October 26, 2021. The Court made a costs award in Amerisur's favour in respect of all the general pollution claims which is enforceable against the 102 Claimants whose claims had been discontinued or struck out by the Court but only after the conclusion of the proceedings and when those costs have been either assessed or agreed.

In July 2022, the preliminary issues trial hearing was held, with experts from both parties addressing their written opinions on the two Colombian law issues. On January 26, 2023, the Court ruled in favor of the Claimants in respect of the two issues, allowing the claims to continue before the Courts in London. Amerisur requested permission to appeal before the Court on the same day. On February 6, 2023, the Court issued its ruling on the written submissions, and reply submissions, filed by the parties on costs and permission to appeal, ordering Amerisur to pay the sum of GBP 330,022 (equivalent to US$ 397,089), and refusing permission to appeal. Consequently, on February 23, 2023, Amerisur requested permission to appeal before the court of appeal.

GeoPark has recognized a provision in its Consolidated Financial Statements for GBP 4,465,600 (equivalent to US$ 5,384,000 as of December 31, 2022) related to this contingent liability, which was originally recognized at the moment of the acquisition of Amerisur in 2020.

Note 30 Trade and other payables

Amounts in US$ '000	2022	2021
V.A.T	8,513	7,473
Trade payables	102,125	86,672
Customer advance payments	481	426
Other short-term advance payments [(a)]	—	1,558
Staff costs to be paid	9,306	17,973
Royalties to be paid	9,403	7,347
Taxes and other debts to be paid	8,963	6,651
To be paid to co-venturers (Note 34)	2,815	953
	141,606	**129,053**
Classified as follows:		
Current	141,606	127,513
Non-current	—	1,540

(a) Advance payment collected in relation with the sale of the Aguada Baguales, El Porvenir and Puesto Touquet Blocks (see Note 36.3.1).

The average credit period (expressed as creditor days) during the year ended December 31, 2022 was 69 days (2021: 89 days).

The fair value of these short-term financial instruments is not individually determined as the carrying amount is a reasonable approximation of fair value.

Note 31 Share-based payment

The Group has established different stock awards programs and other share-based payment plans to incentivize the Directors, senior management and employees, enabling them to benefit from the increased market capitalization of the Company.

During 2018, GeoPark announced the 2018 Equity Incentive Plan (the "Plan") to motivate and reward those employees, directors, consultants and advisors of the Group to perform at the highest level and to further the best interests of the Company and its shareholders. This Plan is designed as a master plan, with a 10-year term, and embraces all equity incentive programs that the Company decides to implement throughout such term. The maximum number of Shares available for issuance under the Plan is 5,000,000 Shares.

In November 2019, the Group approved a share-based compensation program for approximately 800,000 shares to be granted in 2020. The main characteristics of the Stock Awards Programs were:

- Employees not included in the VCP and new hiring were eligible.
- Exercise price was equal to the nominal value of shares.
- Vesting date: January 2, 2023.

- Each employee could receive between three and six salaries (to be pro-rated between the hiring date and the vesting date for new hiring) by achieving the following conditions: continue to be an employee, the stock market price at the date of vesting should be higher than the share price at the date of grant and obtain the Group minimum production, adjusted EBITDA and reserves target for the year of vesting.

The vested shares will be issued after the filing of the Consolidated Financial Statements.

On March 8, 2022, the Company's board of directors approved a pool of approximately 215,000 shares oriented for retention of key employees and new hires bonuses, under the Stock Awards Program. Vesting of the plan is in a three-years period from the grant date.

During 2022, the Company's board of directors, as per recommendation of the Compensation Committee, approved a Long-Term Incentive program ("LTIP") oriented to senior management team. Main characteristics of the program are:

- All the senior management team is eligible.
- Grants are awarded annually for executives.
- The components of the Program are the following:
  - 20% Time-based Restricted Share Units (RSUs) vesting ratably in three equal installments on each of the first three anniversaries of the grant date;
  - 35% Relative Performance Share Units based on relative total shareholder return (TSR) and measured over three-year performance period relative to peer group;
  - 45% Absolute Performance Share Units (PSUs) based on absolute total shareholder return (TSR) and measured over three-year performance period.

In February 2023, 246,110 common shares were allotted to the trustee of the Employee Beneficiary Trust ("EBT") as a consequence of the vesting of the first tranche of the abovementioned plan.

Details of these costs and the characteristics of the different stock awards programs and other share-based payments are described in the following table:

	Awards at the beginning	Awards granted in the year	Awards forfeited	Awards exercised	Awards at year end	Charged to net profit/loss		
						2022	2021	2020
Year of issuance	No. of Shares					Amounts in US$ '000		
2022	—	191,400	—	—	191,400	619	—	—
2020	414,065	—	(8,146)	—	405,919	1,691	862	1,274
Subtotal	**414,065**	**191,400**	**(8,146)**	**—**	**597,319**	**2,310**	**862**	**1,274**
Shares granted to Non-Executive Directors	—	75,636	—	(75,636)	—	1,041	861	665
Shares granted to Executive Directors [(a)]	170,330	257,665	—	(52,058)	375,937	3,560	800	800
VCP [(b)]	—	—	—	—	—	2,016	4,098	5,705
LTIP for executives	—	571,984	—	—	571,984	2,111	—	—
	584,395	**1,096,685**	**(8,146)**	**(127,694)**	**1,545,240**	**11,038**	**6,621**	**8,444**

(a) Includes compensation agreements from CEO transition.

(b) During 2019, the Group approved a plan named Value Creation Plan ("VCP") oriented to key management. As of December 31, 2021, the performance metrics were not achieved to execute this program and is not currently in place.

The awards that are forfeited correspond to employees that had left the Group before vesting date.

Note 32 Interests in Joint operations

The Group has interests in joint operations, which are engaged in the exploration of hydrocarbons in Colombia, Chile, Brazil, Argentina and Ecuador.

GeoPark is the operator in the Llanos 34, Llanos 86, Llanos 87, Llanos 104, Llanos 123, Llanos 124, Mecaya, PUT-8, PUT-9, PUT-36, Tacacho and Terecay Blocks in Colombia, in the Flamenco, Campanario and Isla Norte Blocks in Chile, in the POT-T-785 Block in Brazil, and in the Espejo Block in Ecuador.

The following amounts represent the Group's share in the assets, liabilities and results of the joint operations which have been recognized in the Consolidated Statement of Financial Position and Statement of Income:

Subsidiary / Joint operation	Interest	PP&E	Other Assets	Total Assets	Total Liabilities	Net Assets/ (Liabilities)	Revenue	Operating profit (loss)
2022								
GeoPark Colombia S.A.S.								
Llanos 34 Block	45 %	295,639	2,284	297,923	(2,104)	295,819	721,326	402,425
Llanos 32 Block	12.5 %	2,324	—	2,324	(371)	1,953	9,791	7,066
Llanos 86 Block	50 %	970	—	970	—	970	—	(60)
Llanos 87 Block	50 %	15,038	—	15,038	(41)	14,997	—	(390)
Llanos 94 Block	50 %	576	—	576	(233)	343	—	(5,632)
Llanos 104 Block	50 %	1,001	—	1,001	—	1,001	—	(60)
Llanos 123 Block	50 %	1,172	—	1,172	—	1,172	—	(60)
Llanos 124 Block	50 %	1,207	—	1,207	—	1,207	—	(60)
CPO-5 Block	30 %	199,748	—	199,748	(344)	199,404	184,160	69,422
CPO-4-1 Block	50 %	102	—	102	—	102	—	—
Amerisur Exploración Colombia Limitada Sucursal Colombia								
Mecaya Block	50 %	3,908	—	3,908	(17)	3,891	—	(62)
PUT-8 Block	50 %	7,927	—	7,927	—	7,927	—	(61)
PUT-9 Block	50 %	4,420	—	4,420	—	4,420	—	(62)
PUT-36 Block	50 %	2,931	—	2,931	—	2,931	—	(60)
Tacacho Block	50 %	—	—	—	—	—	—	(3,699)
Terecay Block	50 %	—	—	—	—	—	—	(300)
GeoPark TdF S.p.A.								
Flamenco Block	50 %	—	—	—	(1,314)	(1,314)	—	(261)
Campanario Block	50 %	—	—	—	(422)	(422)	—	(115)
Isla Norte Block	60 %	—	—	—	(160)	(160)	—	(131)
GeoPark Brasil Exploração y Produção de Petróleo e Gas Ltda.								
Manati Field	10 %	5,665	18,537	24,202	(12,602)	11,600	19,873	11,240
POT-T-785	70 %	168	—	168	—	168	—	—
GeoPark Argentina S.A.U.								
CN-V Block	50 %	—	—	—	(14)	(14)	—	(131)
Los Parlamentos Block	50 %	—	—	—	(93)	(93)	—	(176)
Puelen Block	18 %	—	10	10	(105)	(95)	—	(69)
Sierra del Nevado Block	18 %	—	1	1	(4)	(3)	—	(8)
GeoPark Perú S.A.C. - Sucursal Ecuador								
Espejo	50 %	10,727	593	11,320	(5,406)	5,914	—	(5,151)
Perico	50 %	15,195	8,506	23,701	(5,315)	18,386	10,671	4,533

Subsidiary / Joint operation	Interest	PP&E	Other Assets	Total Assets	Total Liabilities	Net Assets/ (Liabilities)	Revenue	Operating profit (loss)
2021								
GeoPark Colombia S.A.S.								
Llanos 34 Block	45 %	260,589	1,866	262,455	(5,573)	256,882	486,779	341,473
Llanos 32 Block	12.5 %	2,730	—	2,730	(197)	2,533	7,690	5,378
Llanos 86 Block	50 %	408	—	408	—	408	—	(60)
Llanos 87 Block	50 %	1,220	—	1,220	—	1,220	—	(60)
Llanos 94 Block	50 %	1,489	—	1,489	(270)	1,219	—	(171)
Llanos 104 Block	50 %	434	—	434	—	434	—	(60)
Llanos 123 Block	50 %	907	—	907	—	907	—	(60)
Llanos 124 Block	50 %	841	—	841	—	841	—	(60)
CPO-5 Block	30 %	210,154	—	210,154	(929)	209,225	88,479	55,131
Amerisur Exploración Colombia Limitada Sucursal Colombia								
Mecaya Block	50 %	3,837	—	3,837	(84)	3,753	—	—
PUT-8 Block	50 %	7,070	—	7,070	—	7,070	—	—
PUT-9 Block	50 %	4,342	—	4,342	—	4,342	—	—
PUT-36 Block	50 %	2,870	—	2,870	—	2,870	—	—
Tacacho Block	50 %	3,629	—	3,629	—	3,629	—	—
Terecay Block	50 %	226	—	226	—	226	—	—
GeoPark TdF S.p.A.								
Flamenco Block	50 %	—	—	—	(2,082)	(2,082)	—	(137)
Campanario Block	50 %	—	—	—	(551)	(551)	—	(106)
Isla Norte Block	60 %	—	—	—	(138)	(138)	—	(122)
GeoPark Brasil Exploração y Produção de Petróleo e Gas Ltda.								
Manati Field	10 %	6,851	18,269	25,120	(13,657)	11,463	20,109	9,899
POT-T-785	70 %	157	—	157	—	157	—	—
GeoPark Argentina S.A.U.								
CN-V Block	50 %	—	149	149	(528)	(379)	—	(839)
Los Parlamentos Block	50 %	—	—	—	—	—	—	(285)
Puelen Block	18 %	—	12	12	(18)	(6)	—	(55)
Sierra del Nevado Block	18 %	—	1	1	(5)	(4)	—	(10)
GeoPark Perú S.A.C. - Sucursal Ecuador								
Espejo	50 %	1,132	78	1,210	(610)	600	—	(589)
Perico	50 %	4,658	1,449	6,107	(4,535)	1,572	—	(669)

Subsidiary / Joint operation	Interest	PP&E	Other Assets	Total Assets	Total Liabilities	Net Assets/ (Liabilities)	Revenue	Operating profit (loss)
2020								
GeoPark Colombia S.A.S.								
Llanos 34 Block	45 %	212,914	2,834	215,748	(6,829)	208,919	273,077	203,386
Llanos 32 Block	12.5 %	1,484	—	1,484	(273)	1,211	5,885	4,248
Llanos 86 Block	50 %	137	—	137	—	137	—	—
Llanos 87 Block	50 %	333	—	333	—	333	—	—
Llanos 94 Block	50 %	42	—	42	(68)	(26)	—	—
Llanos 104 Block	50 %	145	—	145	—	145	—	—
Llanos 123 Block	50 %	248	—	248	—	248	—	—
Llanos 124 Block	50 %	240	—	240	—	240	—	—
Petrodorado South America S.A. Sucursal Colombia								
CPO-5 Block	30 %	218,298	—	218,298	(455)	217,843	29,552	14,398
Amerisur Exploración Colombia Limitada Sucursal Colombia								
Mecaya Block	50 %	1,301	—	1,301	(128)	1,173	—	—
PUT-8 Block	50 %	2,334	—	2,334	—	2,334	—	—
PUT-9 Block	50 %	924	—	924	—	924	—	—
PUT-12 Block	60 %	610	—	610	—	610	—	—
PUT-36 Block	50 %	31	—	31	—	31	—	—
Tacacho Block	50 %	3,591	—	3,591	—	3,591	—	—
Terecay Block	50 %	173	—	173	—	173	—	—
GeoPark TdF S.p.A.								
Flamenco Block	50 %	—	—	—	(1,577)	(1,577)	—	(7,532)
Campanario Block	50 %	—	—	—	(372)	(372)	—	(16,913)
Isla Norte Block	60 %	—	—	—	(132)	(132)	—	(9,418)
GeoPark Brasil Exploração y Produção de Petróleo e Gas Ltda.								
Manati Field	10 %	13,280	15,557	28,837	(11,515)	17,322	12,286	3,339
REC-T-128	70 %	—	1,152	1,152	(52)	1,100	497	(72)
POT-T-785	70 %	79	—	79	—	79	—	—
GeoPark Argentina S.A.U.								
CN-V Block	50 %	—	107	107	(164)	(57)	—	(289)
Los Parlamentos Block	50 %	—	—	—	—	—	—	(244)
Puelen Block	18 %	—	20	20	(106)	(86)	—	(156)
Sierra del Nevado Block	18 %	—	7	7	(6)	1	—	(13)
GeoPark Perú S.A.C.								
Morona	75 %	3,651	607	4,258	(6,622)	(2,364)	—	(36,980)
GeoPark Perú S.A.C. - Sucursal Ecuador								
Espejo	50 %	409	29	438	(131)	307	—	(464)
Perico	50 %	397	52	449	(229)	220	—	(543)

Capital commitments are disclosed in Note 33.2.

Note 33 Commitments

33.1 Royalty and economic rights commitments

33.1.1 Royalty

In Colombia, royalties on production are payable to the Colombian Government and are determined on a field-by-field basis using the level of production sliding scale detailed below:

Average daily production in barrels	Production Royalty rate
Up to 5,000	8%
5,000 to 125,000	8% + (production - 5,000) * 0.1
125,000 to 400,000	20%
400,000 to 600,000	20% + (production - 400,000) * 0.025
Greater than 600,000	25%

The production royalty rate depends on the crude quality. When the API is lower than 15°, the payment is reduced to the 75% of the total calculation.

In Chile, royalties are payable to the Chilean Government. In the Fell Block, royalties are calculated at 5% of crude oil production sold and 3% of gas production sold. In the Flamenco Block, Campanario Block and Isla Norte Block, royalties are calculated at 5% of oil and gas production sold.

In Brazil, the Brazilian National Petroleum, Natural Gas and Biofuels Agency (ANP) is responsible for determining monthly minimum prices for petroleum produced in concessions for purposes of royalties payable with respect to production. Royalties generally correspond to a percentage ranging between 5% and 10% applied to reference prices for oil or natural gas, as established in the relevant bidding guidelines (edital de licitação) and concession agreement. In determining the percentage of royalties applicable to a concession, the ANP takes into consideration, among other factors, the geological risks involved and the production levels expected. In the Manati Block, royalties are calculated at 7.5% of gas production.

33.1.2 Overriding royalty

GeoPark is obligated to pay an overriding royalty of 4% and 2.5%, respectively, to the previous owners of the Llanos 34 and CPO-5 Blocks, based on the production and sale of hydrocarbons discovered in the blocks. During 2022, the Group has accrued US$ 34,032,000 (US$ 22,562,000 in 2021 and US$ 14,018,000 in 2020) in relation with these overriding royalty agreements. Furthermore, there are overriding royalty agreements in place from 1.2% to 8.5% of the net production in the Andaquies, Coati, Mecaya, PUT-8, PUT-9, Tacacho and Terecay Blocks. Since they are exploratory blocks with no production during 2022, these agreements had no impact on the Group's results.

33.1.3 Economic rights

According to each E&P contract, the Colombian National Hydrocarbons Agency ("ANH") has an economic right, offered by the operator at the moment of the ANH bid. This economic right, which is based on the production of the block after royalty discount, is equal to 1% in the Llanos 34 and Llanos 32 Blocks, 23% in the CPO-5 Block and 0% in the Platanillo Block.

When the accumulated production of each field, including the royalties' volume, exceeds 5,000,000 of barrels and the WTI price exceeds certain price level previously determined, the Group should also deliver to ANH a share of the production net of royalties in accordance with a formula defined in each E&P contract, which basically depends on the WTI price and the crude quality.

33.2 Capital commitments

During 2022, the Group incurred investments of US$ 55,245,000 to fulfil its commitments, at GeoPark's working interest.

33.2.1 Colombia

The future investment commitments assumed by GeoPark, at its working interest, are up to:

- Llanos 32 Block: 5 exploratory wells before February 20, 2022. Pursuant to a private agreement with the partner in the block, the investment commitment incurred by GeoPark amounts to US$ 9,225,000. As of the date of these Consolidated Financial Statements, the five exploratory wells have already been drilled and ANH approval of the fulfillment of the investment commitment is pending.

- Llanos 86 Block: 3D seismic and 1 exploratory well (US$ 9,895,000) before March 14, 2025.

- Llanos 87 Block: 3D seismic reprocessing, aerogeophysic and 4 exploratory wells (US$ 13,837,000) before March 9, 2023. As of the date of these Consolidated Financial Statements, GeoPark has drilled three of the four committed exploratory wells and ANH approval of the fulfillment of the investment commitment is pending. In March 2023, the ANH approved our request to extend the exploratory phase 1 until May 14, 2023.

- Llanos 94 Block: 3D seismic acquisition and reprocessing and 3 exploratory wells (US$ 11,470,000) before October 1, 2023. One of the three committed exploratory wells has already been drilled. During 2022, operator of the block submitted to the ANH requests to transfer part of the pending commitments to the Llanos 34 Block. As of the date of these Consolidated Financial Statements, the investments needed to accomplish with those commitments assigned to the Llanos 34 Block have already been incurred and the ANH approval is pending.

- Llanos 104 Block: 3D seismic and 1 exploratory well (US$ 8,767,000) before March 14, 2025.

- Llanos 123 Block: 3D seismic reprocessing, geochemistry and 2 exploratory wells (US$ 7,130,000) before January 14, 2024.

- Llanos 124 Block: 3D seismic acquisition and reprocessing, geochemistry and 3 exploratory wells (US$ 10,555,000) before January 14, 2024.

- CPO-4-1 Block: 1 exploratory well (US$ 2,922,000) before September 19, 2025.

- CPO-5 Block: 3D seismic acquisition, processing and interpretation and 1 exploratory well (US$ 2,794,000) before October 9, 2025. Pursuant to a private agreement with the partner in the block, the investment commitment to be incurred by GeoPark amounts to US$ 9,313,000.

- Coati Block: 3D seismic and 2D seismic acquisition (US$ 4,500,000). The evaluation area is currently suspended. On November 3, 2022, GeoPark submitted to the ANH a request to withdraw from the exploration period of the Coati E&P contract and transfer the pending commitments to other E&P contracts. As of the date of these Consolidated Financial Statements, transfer of investment is being carried out by GeoPark.

- Mecaya Block: 3D seismic or 1 exploratory well (US$ 2,000,000). The exploratory period is currently suspended. Pursuant to a private agreement with the partner in the block, the investment commitment to be incurred by GeoPark amounts to US$ 600,000.

- PUT-8 Block: 3D seismic acquisition and reprocessing and 3 exploratory wells (US$ 13,107,000) before October 15, 2023. Part of the 3D seismic committed in the block has already been acquired during 2020 and 2021. On October 25, 2022, GeoPark submitted to the ANH a request to transfer the investment commitment related to the pending 3D seismic to the Platanillo Block. As of the date of these Consolidated Financial Statements, such investment has been fulfilled and the ANH approval is pending.

- PUT-9 Block: 3D seismic acquisition and 2 exploratory wells (US$ 10,550,000). GeoPark has signed a private agreement with the other partner in the block resulting in the total investment commitment to be incurred by GeoPark amounting to US$ 4,365,000. The exploratory period is currently suspended.

- PUT-14 Block: 2D seismic acquisition and 1 exploratory well (US$ 16,122,000). On March 10, 2022, GeoPark submitted to the ANH a request to withdraw from the PUT-14 E&P contract and transfer the pending commitments to the Platanillo and CPO-5 Blocks. Once total investment is reached through such transfers, ANH will continue with the contract's termination. As of the date of these Consolidated Financial Statements, part of the abovementioned investment has already been incurred and the ANH approval is pending.

- The PUT-36 Block is in a preliminary phase that is suspended as of the date of these Consolidated Financial Statements. During this preliminary phase, GeoPark must request from the Ministry of Interior a certificate that indicates presence or no presence of indigenous communities and develop previous consultation, if applicable. Only when this process has been completed and the corresponding regulatory approvals have been obtained, the blocks will enter into phase 1, where the exploratory commitments are mandatory. The investment commitments for the block over three-years term of phase 1 would be 3D seismic acquisition and 2 exploratory wells (US$ 11,891,000).

- Tacacho Block: 2D seismic acquisition, processing and interpretation (US$ 4,080,000). GeoPark has signed a private agreement with the other partner in the block resulting in the total investment commitment to be incurred by GeoPark amounting to US$ 1,224,000. The exploratory period is currently suspended. On September 21, 2022, GeoPark submitted to the ANH a request for termination of the E&P contract. As of the date of these Consolidated Financial Statements, the request is under review by the ANH.

- Terecay Block: 2D seismic acquisition, processing and interpretation (US$ 4,046,000). GeoPark has signed a private agreement with the other partner in the block resulting in the total investment commitment to be incurred by GeoPark amounting to US$ 2,856,000. The exploratory period is currently suspended. On September 21, 2022, GeoPark submitted to the ANH a request for termination of the E&P contract. As of the date of these Consolidated Financial Statements, the request is under review by the ANH.

33.2.2 Chile

The remaining investment commitment to be assumed 100% by GeoPark for the second exploratory phase in the Campanario and Isla Norte Blocks are up to:

- Campanario Block: 2 exploratory wells before April 25, 2024 (US$ 5,002,000)

- Isla Norte Block: 1 exploratory well before February 19, 2024 (US$ 867,000)

As of December 31, 2022, the Group has established guarantees for its total commitments.

33.2.3 Brazil

The future investment commitments assumed by GeoPark are up to:

- POT-T-785 Block: 3D seismic and electromagnetic survey before April 29, 2025 (US$ 67,000).

- REC-T-58 Block: 3D seismic and electromagnetic survey before February 14, 2025 (US$ 140,000).

- REC-T-67 Block: 3D seismic and electromagnetic survey before February 14, 2025 (US$ 140,000).

- REC-T-77 Block: 3D seismic and electromagnetic survey before February 14, 2025 (US$ 140,000).

- POT-T-834 Block: 3D seismic and electromagnetic survey before February 14, 2025 (US$ 140,000)

33.2.4 Argentina

The investment commitment in the Los Parlamentos Block (50% working interest) for the first exploratory period, ending on October 30, 2022, which includes 1 exploratory well and 3D seismic, amounts to US$ 6,000,000, at GeoPark’s working interest. As of the date of these Consolidated Financial Statements, suspension of the terms of the exploratory period and transfer of the investment commitment to another block is under negotiation.

33.2.5 Ecuador

The investment commitments assumed by GeoPark, at its 50% working interest, in the Espejo and Perico Blocks during the first exploratory period are up to:

- Espejo Block: 3D seismic and 4 exploratory wells before June 17, 2025 (US$ 20,912,000). As of the date of these Consolidated Financial Statements, GeoPark has already performed the 3D seismic and drilled two of the four committed exploratory wells.

- Perico Block: 4 exploratory wells before June 16, 2025 (US$ 18,084,000). As of the date of these Consolidated Financial Statements, three of the four committed exploratory wells have been drilled.

Note 34 Related parties

Controlling interest

The main shareholders of GeoPark Limited, based solely on the 13D and 13G filed with the SEC, as of December 31, 2022, are:

Shareholder	Common shares	Percentage of outstanding common shares
James F. Park [a]	8,817,251	15.30 %
Compass Group LLC [b]	7,525,160	13.06 %
Gerald E. O'Shaughnessy [c]	5,545,080	9.62 %
Renaissance Technologies LLC [d]	3,106,263	5.39 %
Other shareholders	32,628,244	56.62 %
	57,621,998	**100.00 %**

(a) Held by James F. Park directly and indirectly through GoodRock, LLC, which is controlled by Mr. Park. The information set forth above and listed in the table is based solely on the disclosure set forth in Mr. Park's most recent Schedule 13G filed with the SEC on February 13, 2023. 602,400 of Mr. Park's shares have been pledged pursuant to lending arrangements.

(b) The information set forth above and listed in the table is based solely on the disclosure set forth in Compass Group LLC's most recent Schedule 13G filed with the SEC on February 14, 2023.

(c) Held by Mr. O'Shaughnessy directly and indirectly through GP Investments LLP; GPK Holdings, LLC; The Globe Resources Group, Inc.; and other investment vehicles. The information set forth above and listed in the table is based solely on the disclosure set forth in Mr. O'Shaughnessy most recent Schedule 13D filed with the SEC on November 30, 2022.

(d) The information set forth above and listed in the table is based solely on the disclosure set forth in Renaissance's most recent Schedule 13G filed with the SEC on February 13, 2023.

Balances outstanding and transactions with related parties

Account (Amounts in US$´000)	Transaction in the year	Balances at year end	Related Party	Relationship
2022				
To be recovered from co-venturers	—	8,750	Joint Operations	Joint Operations
To be paid to co-venturers	—	(2,815)	Joint Operations	Joint Operations
Geological and geophysical expenses	160	—	Carlos Gulisano	Non-Executive Director [(a)]
Administrative expenses	492	—	Pedro E. Aylwin	Former Executive Director [(b)]
2021				
To be recovered from co-venturers	—	4,680	Joint Operations	Joint Operations
To be paid to co-venturers	—	(953)	Joint Operations	Joint Operations
Geological and geophysical expenses	160	—	Carlos Gulisano	Non-Executive Director [(a)]
Administrative expenses	656	—	Pedro E. Aylwin	Executive Director [(b)]
2020				
To be recovered from co-venturers	—	2,236	Joint Operations	Joint Operations
To be paid to co-venturers	—	(5,760)	Joint Operations	Joint Operations
Geological and geophysical expenses	130	—	Carlos Gulisano	Non-Executive Director [(a)]
Administrative expenses	561	—	Pedro E. Aylwin	Executive Director [(b)]

(a) Corresponding to consultancy services. Carlos Gulisano acted as a Director of the Company until July 2022.

(b) Corresponding to wages and salaries acting as Director of Legal and Governance. In 2022, also includes consultancy services. In addition, Aylwin, Mendoza, Luksic & Valencia Law firm, where Pedro Aylwin is a partner and has a participation through Asesorías e Inversiones A&P Ltda, provided general legal services to all the Chilean entities, in Chilean corporate, labor, environmental, regulatory, and commercial laws.

There have been no other transactions with the board of directors, Executive officers, significant shareholders or other related parties during the year besides the intercompany transactions which have been eliminated in the Consolidated Financial Statements, the normal remuneration of board of directors and other benefits informed in Note 11.

Note 35 Auditors Fees

Amounts in US$'000	2022	2021	2020
Audit fees	885	1,023	926
Audit related fees	85	65	—
Tax services fees	27	47	35
Total Auditors Fees	**997**	**1,135**	**961**

Fees are shown net of VAT and other associated tax charges.

Note 36 Business transactions

36.1 Acquisition of Amerisur Resources Plc

On January 16, 2020, GeoPark acquired the 100% share capital of Amerisur Resources Plc, a company listed on the Alternative Investment Market ("AIM") of the London Stock Exchange. After the acquisition, the company was delisted and its name changed to Amerisur Resources Limited. The principal activities of Amerisur Resources Limited and its subsidiaries ("Amerisur") are exploration, development and production for oil and gas reserves in Latin America. Amerisur owns thirteen production, development and exploration blocks in Colombia (twelve operated blocks in the Putumayo basin and one non-operated block in the Llanos basin) and an export oil pipeline from Colombia to Ecuador named Oleoducto Binacional Amerisur ("OBA").

GeoPark paid a cash consideration of British Pound Sterling ("GBP") 241,682,496, equivalent to US$ 314,163,077 at the transaction date. In relation to the cash consideration, GeoPark was exposed to fluctuations of the GBP as of December 31, 2019. Consequently, the Group decided to manage this exposure by entering into a "Deal Contingent Forward" with a UK Bank, in order to anticipate any currency fluctuation. This forward contract was accounted for as a cash flow hedge as of December 31, 2019 and therefore the effective portion of the changes in its fair value was recognized in Other Reserve within Equity. On January 16, 2020, GeoPark removed that amount from the cash flow hedge reserve and included it directly in the initial cost of the acquired business.

In accordance with the acquisition method of accounting, the acquisition cost was allocated to the underlying assets acquired and liabilities assumed based primarily upon their estimated fair values at the date of acquisition. An income approach (being the net present value of expected future cash flows) was adopted to determine the fair values of the mineral interest. Estimates of expected future cash flows reflect estimates of projected future revenues, production costs and capital expenditures based on our business model. The excess of acquisition cost, if any, over the net identifiable assets acquired represents goodwill.

The following table summarizes the combined consideration paid for the acquired business and the final allocation of fair value of the assets acquired and liabilities assumed for the abovementioned transaction:

Amounts in US$'000	Total
Cash	314,163
Total consideration	**314,163**
Property, plant and equipment (including mineral interest)	276,988
Right-of-use assets	16,674
Deferred income tax asset	4,071
Prepayments and other receivables	30,024
Trade receivables	5,964
Inventories	4,128
Other assets	5,991
Cash and cash equivalents	41,828
Lease liabilities	(17,851)
Provision for other long-term liabilities	(16,519)
Current income tax liability	(3,426)
Trade and other payables	(33,709)
Total identifiable net assets	**314,163**

36.2 Brazil

36.2.1 Manati Block

On November 22, 2020, GeoPark signed an agreement to sell its 10% non-operated working interest in the Manati Block in Brazil. The total consideration amounted to Brazilian reais 144,400,000 (equivalent to US$ 30,478,000 as of March 31, 2022), including a fixed payment of Brazilian reais 124,400,000 plus an earn-out of Brazilian reais 20,000,000, which was subject to obtaining certain regulatory approvals. The transaction was subject to certain conditions that should have been met before March 31, 2022. As of March 31, 2022, the required conditions were not met and GeoPark decided not to extend this deadline. As a result, GeoPark continues to own its 10% interest in the block.

36.2.2 REC-T-128 Block

In 2021, GeoPark performed a farm-out transaction to sell its 70% interest in the REC-T-128 Block in Brazil. The total consideration was US$ 1,100,000, which was collected at closing in 2021, plus a contingent payment of up to US$ 710,000, subject to international oil price and field production performance. On August 1, 2022, GeoPark collected the contingent payment of US$ 710,000.

36.3 Argentina

36.3.1 Aguada Baguales, El Porvenir and Puesto Touquet Blocks

In August 2021, the Company's board of directors approved the decision to evaluate farm-out or divestment opportunities to sell its 100% working interest and operatorship in the Aguada Baguales, El Porvenir and Puesto Touquet Blocks in Argentina, including the associated gas transportation license through the Puesto Touquet pipeline.

On November 3, 2021, GeoPark signed a sale and purchase and assignment agreement for a total consideration of US$ 16,000,000, subject to working capital adjustment. At that moment, GeoPark collected an advance payment of US$ 1,600,000.

The closing of the transaction took place on January 31, 2022, after the corresponding regulatory approvals were granted and GeoPark received the remaining outstanding payment from the purchaser. In April 2022, GeoPark paid a working capital adjustment amounting to US$ 370,000. As a consequence of this transaction, GeoPark recognized a gain of US$ 3,983,000 within Other income (expenses).

As of December 31, 2021, the amount of Property, plant and equipment related to the blocks and the liabilities associated with them had been classified as held for sale. Immediately before the classification as held for sale, the recoverable amount of the blocks was estimated and an impairment reversal of US$ 13,307,000 was recognized in the Consolidated Statement of Income. The reversal was limited so that the carrying amount of the blocks does not exceed the lower of its recoverable amount, or the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the blocks in prior years (see Note 37).

36.4 Peru

36.4.1 Morona Block

On July 15, 2020, GeoPark notified its irrevocable decision to retire from the non-producing Morona Block (Block 64) in Peru, due to extended force majeure, which allows for the termination of the license contract. On April 6, 2021, the final agreement with Petroperu was signed and, on May 31, 2021, the joint operation agreement was terminated. On September 28, 2021, the supreme decree approving the assignment was issued by the Peruvian Government, and the public deed corresponding to that assignment was finally executed by GeoPark and Petroperu on November 15, 2021. Consequently, from such date, all the rights and obligations under the Morona Block license contract are the exclusive responsibility of Petroperu.

During 2020, the Group recognized an impairment of its Property, plant and equipment for a total amount of US$ 33,976,000, wrote-down VAT credits for US$ 6,017,000 and Deferred income tax asset for US$ 8,353,000, recognizing those charges within Other expenses and Income tax expenses, respectively, in the Consolidated Statement of Income, and recognized a provision for environmental obligations for a present value of US$ 1,886,000, with impact in Other expenses in the Consolidated Statement of Income.

Note 37 Impairment test on Property, plant and equipment

The management of the Group considers as cash-generating unit ("CGU") each of the blocks or group of blocks in which the Group has working or economic interests. The blocks with no material investment on property, plant and equipment or with operations that are not linked to oil and gas prices were not subject to the impairment test.

During 2022, a new tax reform approved in Colombia (see Note 16) negatively impacted the expected cash flows for the following years. Additionally, a revision of the estimation of the total proved and probable reserves in the CPO-5 Block (Colombia) at year-end evidenced a decline as compared to the prior year estimation. Management considered these to be impairment indicators for the CPO-5 and the Platanillo Blocks and the Group carried out an impairment review of these CGUs. No impairment indicators were noted in the other CGUs.

The main assumptions taken into account for the impairment tests were:

- The future oil prices have been calculated taking into consideration the oil price curves available in the market, provided by international advisory companies, and weighted through internal estimations in accordance with price curves used by D&M.
- Three oil price scenarios were projected and weighted in order to minimize misleading estimations: low-price, middle-price and high-price (see below table "Oil price scenarios").
- The table "Oil price scenarios" was based on Brent future price estimations; the Group adjusted this market price on its model valuation to reflect the effective price applicable in each location (see Note 3 "Price risk").
- The model valuation was based on the expected cash flow approach.
- The revenues were calculated linking price curves with levels of production according to certified reserves.
- The levels of production have been linked to certified risked P1, P2 and P3 reserves case by case (see Note 4).
- Production and structure costs were estimated considering internal historical data according to GeoPark's own records and aligned to the 2023 approved budget.
- The capital expenditures were estimated considering the drilling campaign necessary to develop the certified reserves.
- The assets subject to impairment test are the ones classified as Oil and Gas properties, Production facilities and machinery and Construction in progress.
- The carrying amount subject to impairment test includes mineral interest, if any.
- The income tax charges have considered future changes in the applicable income tax rates (see Note 16).

Table Oil price scenarios [(a)]:

	Amounts in US$ per Bbl.			
Year	**Low price (15%)**	**Middle price (60%)**	**High price (25%)**	**Weighted market price used for the impairment test**
2023	83.22	92.47	101.71	93.39
2024	60.57	67.30	74.03	67.97
2025	62.02	68.91	75.80	69.60
2026	63.51	70.57	77.62	71.27
Over 2027	65.03	72.26	79.49	72.98

(a) The percentages indicated between brackets represent the Group estimation regarding each price scenario.

As a consequence of the evaluation, the following amounts of impairment loss were (recognized) reversed:

Amounts in US$'000	2022	2021	2020
Chile [(a)]	—	(17,641)	(81,967)
Brazil [(b)]	—	—	(1,717)
Argentina [(c)]	—	13,307	(16,205)
Peru [(d)]	—	—	(33,975)
	—	**(4,334)**	**(133,864)**

(a) Recognition of impairment loss in the Fell Block due to the decline in the proved reserves estimation in 2021 and the commercial viability has been decreased significantly as a consequence of the lower crude prices relative to its high cash costs of production in 2020.

(b) Recognition of impairment loss in the REC-T-128 Block due to the fair value less cost to sale determined in the context of the farm-out process described in Note 36.2.2.

(c) Reversal of impairment loss in the Aguada Baguales and El Porvenir Blocks in 2021 due to the known market price of the blocks in the context of the transaction described in Note 36.3.1. Recognition of impairment loss in the Aguada Baguales and El Porvenir Blocks in 2020 due to the commercial viability has been decreased significantly as a consequence of the lower crude prices relative to its high cash costs of production, which also led to reduced estimates of the quantities of hydrocarbons recoverable.

(d) Recognition of impairment loss in the Morona Block due to the situation described in Note 36.4.1.

With regard to the assessment of value in use for the identified CGUs subject to impairment indicators, Management believes that there are no reasonably possible changes in any of the above key assumptions that would cause the carrying value of the CGUs to materially exceed its recoverable amount.

Note 38 Supplemental information on oil and gas activities (unaudited)

The following information is presented in accordance with ASC No. 932 “Extractive Activities- Oil and Gas”, as amended by ASU 2010 - 03 “Oil and Gas Reserves. Estimation and Disclosures”, issued by FASB in January 2010 in order to align the current estimation and disclosure requirements with the requirements set in the SEC final rules and interpretations, published on December 31, 2008. This information includes the Group’s oil and gas production activities carried out in each country.

Table 1 - Costs incurred in exploration, property acquisitions and development

The following table presents those costs capitalized as well as expensed that were incurred during each of the years ended December 31, 2022, 2021 and 2020. The acquisition of properties includes the cost of acquisition of proved or unproved oil and gas properties. Exploration costs include geological and geophysical costs, costs necessary for retaining undeveloped properties, drilling costs and exploratory wells equipment. Development costs include drilling costs and equipment for developmental wells, the construction of facilities for extraction, treatment and storage of hydrocarbons and all necessary costs to maintain facilities for the existing developed reserves.

Amounts in US$‘000	Colombia	Chile	Brazil	Argentina	Ecuador	Total
Year ended December 31, 2022						
Acquisition of properties						
Proved	—	—	—	—	—	—
Unproved	—	—	—	—	—	—
Total property acquisition	**—**	**—**	**—**	—	**—**	**—**
Exploration	48,771	116	—	779	26,521	76,187
Development [(a)]	89,231	9,952	(212)	—	648	99,619
Total costs incurred	**138,002**	**10,068**	**(212)**	**779**	**27,169**	**175,806**

Amounts in US$‘000	Colombia	Chile	Brazil	Argentina	Total
Year ended December 31, 2021					
Acquisition of properties					
Proved	—	—	—	—	—
Unproved	—	—	—	—	—
Total property acquisition	**—**	**—**	**—**	**—**	**—**
Exploration	40,828	3,940	3	998	45,769
Development [(a)]	81,310	1,900	(2,212)	2	81,000
Total costs incurred	**122,138**	**5,840**	**(2,209)**	**1,000**	**126,769**

Amounts in US$‘000	Colombia	Chile	Brazil	Argentina	Total
Year ended December 31, 2020					
Acquisition of properties					
Proved	202,913	—	—	—	202,913
Unproved	73,310	—	—	—	73,310
Total property acquisition	**276,223**	**—**	**—**	**—**	**276,223**
Exploration	19,142	9,447	668	694	29,951
Development [(a)]	51,793	3,580	412	(3,855)	51,930
Total costs incurred	**70,935**	**13,027**	**1,080**	**(3,161)**	**81,881**

[(a)] Includes the effect of change in estimate of assets retirement obligations.

Table 2 - Capitalized costs related to oil and gas producing activities

The following table presents the capitalized costs as of December 31, 2022, 2021 and 2020, for proved and unproved oil and gas properties, and the related accumulated depreciation as of those dates.

Amounts in US$'000	Colombia	Chile	Brazil	Ecuador	Total
As of December 31, 2022					
Proved properties [a]					
Equipment, camps and other facilities	144,672	74,490	3,565	—	222,727
Mineral interest and wells	672,424	343,926	44,716	18,191	1,079,257
Other uncompleted projects	16,099	113	268	—	16,480
Unproved properties	102,760	—	290	9,991	113,041
Gross capitalized costs	**935,955**	**418,529**	**48,839**	**28,182**	**1,431,505**
Accumulated depreciation	(354,981)	(371,171)	(42,885)	(2,316)	(771,353)
Total net capitalized costs	**580,974**	**47,358**	**5,954**	**25,866**	**660,152**

[a] Includes capitalized amounts related to asset retirement obligations.

Amounts in US$'000	Colombia	Chile	Brazil	Argentina	Total
As of December 31, 2021					
Proved properties [a]					
Equipment, camps and other facilities	125,078	72,766	3,333	—	201,177
Mineral interest and wells	580,931	334,993	42,008	—	957,932
Other uncompleted projects	26,136	818	250	—	27,204
Unproved properties [b]	94,419	—	271	—	94,690
Gross capitalized costs	**826,564**	**408,577**	**45,862**	**—**	**1,281,003**
Accumulated depreciation	(282,616)	(358,417)	(38,741)	—	(679,774)
Total net capitalized costs	**543,948**	**50,160**	**7,121**	**—**	**601,229**

[a] Includes capitalized amounts related to asset retirement obligations, impairment loss recognized in Chile for US$ 17,641,000 and impairment loss reversed in Argentina for US$ 13,307,000.

[b] Do not include Ecuador capitalized costs.

Amounts in US$'000	Colombia	Chile	Brazil	Argentina	Total
As of December 31, 2020					
Proved properties [a]					
Equipment, camps and other facilities	115,577	74,363	3,580	4,309	197,829
Mineral interest and wells	511,040	348,366	47,729	61,482	968,617
Other uncompleted projects [b]	13,048	2,158	245	26	15,477
Unproved properties [c]	77,388	—	432	—	77,820
Gross capitalized costs	**717,053**	**424,887**	**51,986**	**65,817**	**1,259,743**
Accumulated depreciation	(228,929)	(345,611)	(38,273)	(45,619)	(658,432)
Total net capitalized costs	**488,124**	**79,276**	**13,713**	**20,198**	**601,311**

[a] Includes capitalized amounts related to asset retirement obligations, impairment loss in Chile, Argentina and Brazil for US$ 81,967,000, US$ 16,205,000 and US$ 1,717,000, respectively.

[b] Do not include Peru capitalized costs.

[c] Do not include Ecuador capitalized costs.

Table 3 - Results of operations for oil and gas producing activities

The breakdown of results of the operations shown below summarizes revenues and expenses directly associated with oil and gas producing activities for the years ended December 31, 2022, 2021 and 2020. Income tax for the years presented was calculated utilizing the statutory tax rates.

Amounts in US$'000	Colombia	Chile	Brazil	Argentina	Ecuador	Total
Year ended December 31, 2022						
Revenue	978,423	29,196	19,873	1,962	10,671	1,040,125
Production costs, excluding depreciation						
Operating costs	(78,323)	(12,961)	(3,753)	(1,306)	(3,220)	(99,563)
Royalties and economic rights	(249,303)	(1,165)	(1,546)	(273)	—	(252,287)
Total production costs	**(327,626)**	**(14,126)**	**(5,299)**	**(1,579)**	**(3,220)**	**(351,850)**
Exploration expenses [(a)]	(28,424)	(116)	—	(779)	(4,768)	(34,087)
Accretion expense [(b)]	(621)	(1,516)	(504)	—	—	(2,641)
Depreciation, depletion and amortization	(72,386)	(12,754)	(1,509)	—	(2,315)	(88,964)
Results of operations before income tax	**549,366**	**684**	**12,561**	**(396)**	**368**	**562,583**
Income tax (expense) benefit	(192,278)	(103)	(4,271)	—	(92)	(196,744)
Results of oil and gas operations	**357,088**	**581**	**8,290**	**(396)**	**276**	**365,839**

Amounts in US$'000	Colombia	Chile	Brazil	Argentina	Total
Year ended December 31, 2021					
Revenue	618,268	21,471	20,109	28,695	688,543
Production costs, excluding depreciation					
Operating costs	(72,043)	(10,280)	(2,954)	(14,490)	(99,767)
Royalties and economic rights	(106,341)	(770)	(1,642)	(4,270)	(113,023)
Total production costs	**(178,384)**	**(11,050)**	**(4,596)**	**(18,760)**	**(212,790)**
Exploration expenses [(a)]	(11,276)	(4,509)	—	(998)	(16,783)
Accretion expense [(b)]	(576)	(1,319)	(535)	(710)	(3,140)
Impairment loss for non-financial assets	—	(17,641)	—	13,307	(4,334)
Depreciation, depletion and amortization	(54,588)	(12,806)	(2,933)	(8,152)	(78,479)
Results of operations before income tax	**373,444**	**(25,854)**	**12,045**	**13,382**	**373,017**
Income tax (expense) benefit	(115,768)	3,878	(4,095)	(4,684)	(120,669)
Results of oil and gas operations	**257,676**	**(21,976)**	**7,950**	**8,698**	**252,348**

Amounts in US$'000	Colombia	Chile	Brazil	Argentina	Total
Year ended December 31, 2020					
Revenue	334,606	21,704	12,783	24,599	393,692
Production costs, excluding depreciation					
Operating costs	(61,866)	(9,491)	(2,827)	(15,013)	(89,197)
Royalties and economic rights	(30,453)	(753)	(1,049)	(3,620)	(35,875)
Total production costs	**(92,319)**	**(10,244)**	**(3,876)**	**(18,633)**	**(125,072)**
Exploration expenses [(a)]	(12,493)	(50,301)	(1,000)	(694)	(64,488)
Accretion expense [(b)]	(670)	(1,358)	(867)	(1,381)	(4,276)
Impairment loss for non-financial assets	—	(81,967)	(1,717)	(16,205)	(99,889)
Depreciation, depletion and amortization	(56,720)	(32,233)	(2,488)	(14,723)	(106,164)
Results of operations before income tax	**172,404**	**(154,399)**	**2,835**	**(27,037)**	**(6,197)**
Income tax (expense) benefit	(55,169)	23,160	(964)	8,111	(24,862)
Results of oil and gas operations	**117,235**	**(131,239)**	**1,871**	**(18,926)**	**(31,059)**

(a) Do not include Peru and Ecuador costs.

(b) Represents accretion of ARO and other environmental liabilities.

Table 4 - Reserve quantity information

Estimated oil and gas reserves

Proved reserves represent estimated quantities of oil (including crude oil and condensate) and natural gas, which available geological and engineering data demonstrates with reasonable certainty to be recoverable in the future from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods. The choice of method or combination of methods employed in the analysis of each reservoir was determined by the stage of development, quality and reliability of basic data, and production history.

The Group believes that its estimates of remaining proved recoverable oil and gas reserve volumes are reasonable and such estimates have been prepared in accordance with the SEC Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008.

The Group estimates its reserves at least once a year. The Group's reserves estimation as of December 31, 2022, 2021, 2020 and 2019 was based on the DeGolyer and MacNaughton Reserves Report (the "D&M Reserves Report"). DeGolyer and MacNaughton Corp. prepared its proved oil and natural gas reserve estimates in accordance with Rule 4-10 of Regulation S–X, promulgated by the SEC, and in accordance with the oil and gas reserves disclosure provisions of ASC 932 of the FASB Accounting Standards Codification (ASC) relating to Extractive Activities - Oil and Gas (formerly SFAS no. 69 Disclosures about Oil and Gas Producing Activities).

Reserves engineering is a subjective process of estimation of hydrocarbon accumulation, which cannot be exactly measured, and the reserve estimation depends on the quality of available information and the interpretation and judgement of the engineers and geologists. Therefore, the reserves estimations, as well as future production profiles, are often different than the quantities of hydrocarbons which are finally recovered. The accuracy of such estimations depends, in general, on the assumptions on which they are based.

The estimated GeoPark net proved reserves for the properties evaluated as of December 31, 2022, 2021, 2020 and 2019 are summarized as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	As of December 31, 2022		As of December 31, 2021		As of December 31, 2020		As of December 31, 2019	
	Oil and condensate (Mbbl)	Natural gas (MMcf)	Oil and condensate (Mbbl)	Natural gas (MMcf)	Oil and condensate (Mbbl)	Natural gas (MMcf)	Oil and condensate (Mbbl)	Natural gas (MMcf)
Net proved developed								
Colombia [(a)]	46,623	1,065	47,766	1,207	43,817	1,695	39,397	2,319
Chile [(b)]	1,115	14,103	755	15,196	798	19,054	898	14,406
Brazil [(c)]	8	9,443	43	13,601	34	13,927	48	14,872
Argentina [(d)]	—	—	1,186	3,379	1,685	5,599	1,658	5,785
Ecuador [(e)]	322	—	—	—	—	—	—	—
Total consolidated	**48,068**	**24,611**	**49,750**	**33,383**	**46,334**	**40,275**	**42,001**	**37,382**
Net proved undeveloped								
Colombia [(f)]	17,765	—	31,019	—	45,240	—	51,212	—
Chile [(b)]	476	—	575	1,563	1,229	5,661	2,809	6,413
Argentina [(g)]	—	—	603	—	104	—	1,370	450
Peru [(h)]	—	—	—	—	—	—	19,210	—
Total consolidated	**18,241**	**—**	**32,197**	**1,563**	**46,573**	**5,661**	**74,601**	**6,863**
Total proved reserves	**66,309**	**24,611**	**81,947**	**34,946**	**92,907**	**45,936**	**116,602**	**44,245**

(a) Llanos 34 Block, CPO-5 Block, Llanos 32 Block and Platanillo Block account for 84%, 11%, 1% and 4% (Llanos 34 Block, CPO-5 Block, Llanos 32 Block and Platanillo Block account for 88%, 8%, 2% and 2% in 2021, Llanos 34

Block, CPO-5 Block, Llanos 32 Block and Platanillo Block account for 86%, 8%, 3% and 3% in 2020, and Llanos 34 Block and Llanos 32 Block account for 97% and 3% in 2019) of the proved developed reserves, respectively.

(b) Fell Block accounts for 100% of the reserves.

(c) BCAM-40 Block accounts for 100% of the reserves.

(d) Aguada Baguales Block, Puesto Touquet Block, and El Porvenir Block account for 45%, 21% and 33% in 2021 (50%, 26% and 24% in 2020, and 49%, 30% and 21% in 2019) of the proved developed reserves, respectively.

(e) Perico Block and Espejo Block account for 85% and 15% of the reserves, respectively.

(f) Llanos 34 Block, Llanos 32 Block, CPO-5 Block and Platanillo Block account 85%, 7%, 3% and 5% (Llanos 34 Block, Llanos 32 Block, CPO-5 Block and Platanillo Block account 88%, 5%, 5% and 3% in 2021, Llanos 34 Block, Llanos 32 Block and CPO-5 Block account 91%, 5% and 4% in 2020, and Llanos 34 Block and Llanos 32 Block account 96% and 4% in 2019) of the proved undeveloped reserves, respectively.

(g) Aguada Baguales Block accounts for 100% of the proved undeveloped reserves.

(h) Morona Block accounted for 100% of the reserves.

Table 5 - Net proved reserves of oil, condensate and natural gas

Net proved reserves (developed and undeveloped) of oil and condensate:

Thousands of barrels	Colombia	Chile	Brazil	Argentina	Peru	Ecuador	Total
Reserves as of December 31, 2019	**90,609**	**3,707**	**48**	**3,028**	**19,210**	**—**	**116,602**
Increase (decrease) attributable to:							
Revisions [a]	(1,964)	(1,825)	(7)	(734)	—	—	(4,530)
Extensions and discoveries [b]	4,545	279	—	—	—	—	4,824
Purchase or (Disposal) of Minerals in place [c]	6,853	—	—	—	(19,210)	—	(12,357)
Production	(10,986)	(134)	(7)	(505)	—	—	(11,632)
Reserves as of December 31, 2020	**89,057**	**2,027**	**34**	**1,789**	**—**	**—**	**92,907**
Increase (decrease) attributable to:							
Revisions [d]	(3,207)	(597)	18	(169)	—	—	(3,955)
Extensions and discoveries [e]	3,375	—	—	603	—	—	3,978
Production	(10,440)	(100)	(9)	(434)	—	—	(10,983)
Reserves as of December 31, 2021	**78,785**	**1,330**	**43**	**1,789**	**—**	**—**	**81,947**
Increase (decrease) attributable to:							
Revisions [f]	(2,677)	422	(27)	—	—	—	(2,282)
Extensions and discoveries [g]	204	—	—	—	—	632	836
Disposal of Minerals in place [h]	—	—	—	(1,760)	—	—	(1,760)
Production	(11,924)	(161)	(8)	(29)	—	(310)	(12,432)
Reserves as of December 31, 2022	**64,388**	**1,591**	**8**	**—**	**—**	**322**	**66,309**

(a) For the year ended December 31, 2020, the Group's oil and condensate proved reserves were revised downward by 4.5 mmbbl. The primary factors leading to the above were:
- Lower average oil prices resulted in a 4.2 mmbbl, 1.1 mmbbl and 0.3 mmbbl decrease in reserves from the blocks in Colombia, Argentina and Chile, respectively.
- A reduction of 1.6 mmbbl in Chile due to the revision of the type well in the Kiaku and Loij fields and a reduction in Argentina of 0.2 mmbbl associated to the revision of the type of well in the Aguada Baguales fields.
- Lower than expected performance from the existing wells in Colombia that reduced the proved developed reserves from the Jacana, Tigana and Tigui fields (2.8 mmbbl).
- Such decrease was partially offset by a better performance of proved undeveloped reserves in Colombia (5.1 mmbbl) originated by a new estimation of original oil in place and better type wells considered in the Jacana and Tigana fields. In addition, the proved developed reserves increased in the Aguada Baguales Block in Argentina (0.5 mmbbl) and the Konawentru and Guanaco Fields in Chile of 0.1 mmbbl due to better performance of the existing wells.

(b) In Colombia, the extensions and discoveries are primary due to the Tigui Field appraisal wells and in Chile are due to the Jauke Field discovery in the Fell Block.

(c) Purchase of Minerals in place refers to the CPO-5 and Platanillo Blocks acquisition during 2020 in Colombia. The reduction in Peru is due to the decision to retire from the Morona Block (see Note 36.4.1).

[(d)] For the year ended December 31, 2021, the Group's oil and condensate proved reserves were revised downward by 4.0 mmbbl. The primary factors leading to the above were:
- Lower than expected performance from the existing wells that reduced the proved developed reserves in Colombia (8.9 mmbbl), in Argentina (0.3 mmbbl), and in Chile (0.3 mmbbl).
- A decrease of 0.6 mmbbl in Chile due to a change in a previously adopted development plan in the Fell Block.
- Such decrease was partially offset by a higher average oil prices resulted in a 5.7 mmbbl, 0.1 mmbbl and 0.3 mmbbl increase in reserves from the blocks in Colombia, Argentina and Chile, respectively.

[(e)] In Colombia, the extensions and discoveries are primary due to the Tigui Field appraisal wells and in Argentina are due to the Aguada Baguales Field.

[(f)] For the year ended December 31, 2022, the Group's oil and condensate proved reserves were revised downward by 2.3 mmbbl. The primary factors leading to the above were:
- A decrease of 3.6 mmbbl in Colombia due to a change in the royalties payment in certain fields from cash to kind.
- Such decrease was partially offset by a higher average oil prices resulted in a 0.6 mmbbl and 0.1 mmbbl increase in reserves from the blocks in Colombia and Chile, respectively.
- Higher than expected performance from the existing wells that increase the proved reserves in Colombia (0.3 mmbbl) and in Chile (0.3 mmbbl).

[(g)] In Colombia, the extensions and discoveries are primary due to the Cante Flamenco new field in CPO-5 Block and in Ecuador are due to the Jandaya, Yin and Tui new fields in the Perico Block and the Pashuri field in the Espejo Block.

[(h)] The disposal in Argentina is due to the decision of selling the Group's working interest and operatorship in the Aguada Baguales, El Porvenir and Puesto Touquet Blocks in Argentina (see Note 36.3.1)..

Net proved reserves (developed and undeveloped) of natural gas:

Millions of cubic feet	Colombia	Chile	Brazil	Argentina	Total
Reserves as of December 31, 2019	**2,319**	**20,819**	**14,872**	**6,235**	**44,245**
Increase (decrease) attributable to:					
Revisions [(a)]	(211)	(385)	1,840	889	2,133
Extensions and discoveries [(b)]	—	10,456	—	—	10,456
Production	(413)	(6,175)	(2,785)	(1,525)	(10,898)
Reserves as of December 31, 2020	**1,695**	**24,715**	**13,927**	**5,599**	**45,936**
Increase (decrease) attributable to:					
Revisions [(c)]	14	(3,553)	3,470	(636)	(705)
Production	(502)	(4,403)	(3,796)	(1,584)	(10,285)
Reserves as of December 31, 2021	**1,207**	**16,759**	**13,601**	**3,379**	**34,946**
Increase (decrease) attributable to:					
Revisions [(d)]	141	1,501	(886)	—	756
Disposal of Minerals in place [(e)]	—	—	—	(3,227)	(3,227)
Production	(283)	(4,157)	(3,272)	(152)	(7,864)
Reserves as of December 31, 2022	**1,065**	**14,103**	**9,443**	**—**	**24,611**

[(a)] For the year ended December 31, 2020, the Group's proved natural gas reserves were revised upwards by 2.1 billion cubic feet. This was the combined effect of:
- An increase of proved developed reserves due to better performance of existing wells in Chile (7.9 billion cubic feet) mostly associated to the Jauke and Ache Fields, in Brazil (3.0 billion cubic feet) associated to new gas sales plateau in 2021 and forward which leads to better-than-expected performance of the Manati Field and in Argentina (1.9 billion cubic feet) due to better performance of the Puesto Touquet and El Porvenir Blocks.
- The above was partially offset by lower-than-expected performance of proved undeveloped reserves in Chile (5.8 billion cubic feet) due to revisions of the type of well in the Pampa Larga Field.
- Lower average prices resulted in a decrease of 2.5 billion cubic feet, 1.2 billion cubic feet and 1.2 billion cubic feet reduction in gas reserves in Chile, Brazil and Argentina, respectively.

[(b)] The extensions and discoveries are primary due to the Jauke Field discovery in the Fell Block, in Chile.

[(c)] For the year ended December 31, 2021, the Group's proved natural gas reserves were revised downward by 0.7 billion cubic feet. This was the combined effect of:

- A decrease of proved developed reserves due to lower performance of existing wells in Argentina (1.6 billion cubic feet) and in Chile (2.7 billion cubic feet) partially offset by better-than-expected performance in the Manati Field in Brazil (2.5 billion cubic feet).
- A decrease of 3.4 billion cubic feet in Chile due to the revision of the type well associated with the incremental activity that reduced the proved undeveloped reserves.
- A decrease of 1.5 billion cubic feet in Chile due to a change in a previously adopted development plan in the Fell Block.
-Such decrease was partially offset by higher average prices which resulted in an increase of 4.0 billion cubic feet, 1 billion cubic feet and 1 billion cubic feet in Chile, Brazil, and Argentina, respectively.

(d) For the year ended December 31, 2022, the Group's proved natural gas reserves were revised upwards by 0.8 billion cubic feet. This was the combined effect of:
- An increase of proved reserves due to better performance of existing wells in Chile (0.8 billion cubic feet) and the Llanos 32 block in Colombia (0.1 billion cubic feet).
- Higher average prices resulted in an increase of 0.7 billion cubic feet and 0.8 billion cubic feet increase in gas reserves in Chile and Brazil, respectively.
- The above was partially offset by lower-than-expected performance of Manati Field in Brazil (1.6 billion cubic feet).

(e) The disposal in Argentina is due to the decision of selling the Group's working interest and operatorship in the Aguada Baguales, El Porvenir and Puesto Touquet Blocks in Argentina (see Note 36.3.1).

Revisions refer to changes in interpretation of discovered accumulations and some technical and logistical needs in the area obliged to modify the timing and development plan of certain fields under appraisal and development phases.

Table 6 - Standardized measure of discounted future net cash flows related to proved oil and gas reserves

The following table discloses estimated future net cash flows from future production of proved developed and undeveloped reserves of crude oil, condensate and natural gas. As prescribed by SEC Modernization of Oil and Gas Reporting rules and ASC 932 of the FASB Accounting Standards Codification (ASC) relating to Extractive Activities – Oil and Gas (formerly SFAS no. 69 Disclosures about Oil and Gas Producing Activities), such future net cash flows were estimated using the average first day-of-the-month price during the 12-month period for 2022, 2021 and 2020 and using a 10% annual discount factor. Future development and abandonment costs include estimated drilling costs, development and exploitation installations and abandonment costs. These future development costs were estimated based on evaluations made by the Group. The future income tax was calculated by applying the statutory tax rates in effect in the respective countries in which we have interests, as of the date this supplementary information was filed.

This standardized measure is not intended to be and should not be interpreted as an estimate of the market value of the Group's reserves. The purpose of this information is to give standardized data to help the users of the financial statements to compare different companies and make certain projections. It is important to point out that this information does not include, among other items, the effect of future changes in prices, costs and tax rates, which past experience indicates that are likely to occur, as well as the effect of future cash flows from reserves which have not yet been classified as proved reserves, of a discount factor more representative of the value of money over the lapse of time and of the risks inherent to the production of oil and gas. These future changes may have a significant impact on the future net cash flows disclosed below. For all these reasons, this information does not necessarily indicate the perception the Group has on the discounted future net cash flows derived from the reserves of hydrocarbons.

Amounts in US$'000	Colombia	Chile	Brazil	Argentina	Ecuador	Total
As of December 31, 2022						
Future cash inflows	5,229,599	190,449	65,002	—	26,553	5,511,603
Future production costs	(1,633,818)	(72,411)	(29,519)	—	(8,094)	(1,743,842)
Future development costs	(182,701)	(40,659)	(1,955)	—	(297)	(225,612)
Future income taxes	(1,191,658)	—	(1,761)	—	—	(1,193,419)
Undiscounted future net cash flows	**2,221,422**	**77,379**	**31,767**	**—**	**18,162**	**2,348,730**
10% annual discount	(839,621)	(13,094)	(8,856)	—	(2,504)	(864,075)
Standardized measure of discounted future net cash flows	**1,381,801**	**64,285**	**22,911**	**—**	**15,658**	**1,484,655**
As of December 31, 2021						
Future cash inflows	4,381,191	136,152	89,208	109,678	—	4,716,229
Future production costs	(1,715,554)	(69,067)	(34,930)	(61,660)	—	(1,881,211)
Future development costs	(197,461)	(40,339)	(1,955)	(49,200)	—	(288,955)
Future income taxes	(754,205)	—	(3,449)	(2,947)	—	(760,601)
Undiscounted future net cash flows	**1,713,971**	**26,746**	**48,874**	**(4,129)**	**—**	**1,785,462**
10% annual discount	(496,150)	6,121	(7,171)	4,471	—	(492,729)
Standardized measure of discounted future net cash flows	**1,217,821**	**32,867**	**41,703**	**342**	**—**	**1,292,733**
As of December 31, 2020						
Future cash inflows	2,561,947	130,200	68,857	83,125	—	2,844,129
Future production costs	(850,029)	(82,290)	(36,254)	(65,536)	—	(1,034,109)
Future development costs	(197,859)	(28,620)	(2,355)	(24,640)	—	(253,474)
Future income taxes	(409,276)	—	(327)	—	—	(409,603)
Undiscounted future net cash flows	**1,104,783**	**19,290**	**29,921**	**(7,051)**	**—**	**1,146,943**
10% annual discount	(345,550)	(2,258)	(4,543)	7,032	—	(345,319)
Standardized measure of discounted future net cash flows	**759,233**	**17,032**	**25,378**	**(19)**	**—**	**801,624**

Table 7 - Changes in the standardized measure of discounted future net cash flows from proved reserves

Amounts in US$'000	Colombia	Chile	Brazil	Argentina	Peru	Ecuador	Total
Present value as of December 31, 2019	**1,313,572**	**104,223**	**43,382**	**11,341**	**121,217**	**—**	**1,593,735**
Sales of hydrocarbon, net of production costs	(221,620)	(12,803)	8,080	(10,454)	—	—	(236,797)
Net changes in sales price and production costs	(975,716)	(117,895)	(14,580)	(113)	—	—	(1,108,304)
Changes in estimated future development costs	514,317	20,870	(19,606)	(2,587)	—	—	512,994
Extensions and discoveries less related costs	59,898	13,914	—	—	—	—	73,812
Development costs incurred	69,694	10,743	394	445	—	—	81,276
Revisions of previous quantity estimates	(27,190)	(13,002)	3,519	(10)	—	—	(36,683)
Purchase or (Disposal) of Minerals in place	90,315	—	—	—	(121,217)	—	(30,902)
Net changes in income taxes	(281,264)	—	(290)	—	—	—	(281,554)
Accretion of discount	217,227	10,982	4,479	1,359	—	—	234,047
Present value as of December 31, 2020	**759,233**	**17,032**	**25,378**	**(19)**	**—**	**—**	**801,624**
Sales of hydrocarbon, net of production costs	(516,844)	(11,520)	(15,677)	(16,855)	—	—	(560,896)
Net changes in sales price and production costs	924,875	64,048	19,393	(3,145)	—	—	1,005,171
Changes in estimated future development costs	96,364	(18,731)	861	20,674	—	—	99,168
Extensions and discoveries less related costs	80,933	—	—	(1,020)	—	—	79,913
Development costs incurred	87,877	4,111	—	—	—	—	91,988
Revisions of previous quantity estimates	(76,850)	(23,776)	11,957	465	—	—	(88,204)
Net changes in income taxes	(254,618)	—	(2,780)	244	—	—	(257,154)
Accretion of discount	116,851	1,703	2,571	(2)	—	—	121,123
Present value as of December 31, 2021	**1,217,821**	**32,867**	**41,703**	**342**	**—**	**—**	**1,292,733**
Sales of hydrocarbon, net of production costs	(891,534)	(15,317)	(14,697)	—	—	(2,732)	(924,280)
Net changes in sales price and production costs	956,926	39,457	(6,909)	—	—	—	989,474
Changes in estimated future development costs	93,657	(22,675)	(933)	—	—	(10,483)	59,566
Extensions and discoveries less related costs	6,754	—	—	—	—	28,873	35,627
Development costs incurred	94,195	11,153	—	—	—	—	105,348
Revisions of previous quantity estimates	(87,851)	15,513	(2,441)	—	—	—	(74,779)
Disposal of Minerals in place	—	—	—	(342)	—	—	(342)
Net changes in income taxes	(205,370)	—	1,673	—	—	—	(203,697)
Accretion of discount	197,203	3,287	4,515	—	—	—	205,005
Present value as of December 31, 2022	**1,381,801**	**64,285**	**22,911**	**—**	**—**	**15,658**	**1,484,655**

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