GEOPARK LIMITED

CONSOLIDATED
FINANCIAL STATEMENTS

As of and for the year ended 31 December 2017

Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
GeoPark Limited

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statement of financial position of GeoPark Limited and its subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income and of comprehensive income, changes in equity and cash flows, for each of the three years in the period ended December 31, 2017, including 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 as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("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 of these consolidated financial statements 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

PRICE WATERHOUSE & CO. S.R.L.

By (Partner)

Ezequiel L. Mirazón

Autonomous City of Buenos Aires, Argentina
March 7, 2018

We have served as the Company’s auditor since 2009.

CONSOLIDATED STATEMENT OF INCOME

Amounts in US$ ´000	Note	2017	2016	2015
REVENUE	7	330,122	192,670	209,690
Commodity risk management contracts	8	(15,448)	(2,554)	-
Production and operating costs	9	(98,987)	(67,235)	(86,742)
Geological and geophysical expenses	12	(7,694)	(10,282)	(13,831)
Administrative expenses	13	(42,054)	(34,170)	(37,471)
Selling expenses	14	(1,136)	(4,222)	(5,211)
Depreciation		(74,885)	(75,774)	(105,557)
Write-off of unsuccessful exploration efforts	20	(5,834)	(31,366)	(30,084)
Impairment loss reversed (recognised) for non-financial assets	20-36	-	5,664	(149,574)
Other expenses		(5,088)	(1,344)	(13,711)
OPERATING PROFIT (LOSS)		**78,996**	**(28,613)**	**(232,491)**
Financial expenses	15	(53,511)	(36,229)	(36,924)
Financial income	15	2,016	2,128	1,269
Foreign exchange (loss) gain	15	(2,193)	13,872	(33,474)
PROFIT (LOSS) BEFORE INCOME TAX		**25,308**	**(48,842)**	**(301,620)**
Income tax (expense) benefit	17	(43,145)	(11,804)	17,054
LOSS FOR THE YEAR		**(17,837)**	**(60,646)**	**(284,566)**
Attributable to:				
Owners of the Company		(24,228)	(49,092)	(234,031)
Non-controlling interest		6,391	(11,554)	(50,535)
Losses per share (in US$) for loss attributable to owners of the Company. Basic	19	**(0.40)**	**(0.82)**	**(4.05)**
Losses per share (in US$) for loss attributable to owners of the Company. Diluted	19	**(0.40)**	**(0.82)**	**(4.05)**

The notes on pages 8 to 80 are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Amounts in US$ ´000	2017	2016	2015
Loss for the year	(17,837)	(60,646)	(284,566)
Other comprehensive income:			
Items that may be subsequently reclassified to profit or loss			
Currency translation differences	(512)	7,102	(1,001)
Total comprehensive loss for the year	**(18,349)**	**(53,544)**	**(285,567)**
Attributable to:			
Owners of the Company	(24,740)	(41,990)	(235,032)
Non-controlling interest	6,391	(11,554)	(50,535)

The notes on pages 8 to 80 are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

Amounts in US$ ´000	Note	2017	2016
ASSETS			
NON CURRENT ASSETS			
Property, plant and equipment	20	517,403	473,646
Prepaid taxes	22	3,823	2,852
Other financial assets	25	22,110	19,547
Deferred income tax asset	18	27,636	23,053
Prepayments and other receivables	24	235	241
TOTAL NON CURRENT ASSETS		**571,207**	**519,339**
CURRENT ASSETS			
Inventories	23	5,738	3,515
Trade receivables	24	19,519	18,426
Prepayments and other receivables	24	7,518	7,402
Prepaid taxes	22	26,048	15,815
Other financial assets	25	21,378	2,480
Cash and cash equivalents	25	134,755	73,563
TOTAL CURRENT ASSETS		**214,956**	**121,201**
TOTAL ASSETS		**786,163**	**640,540**
TOTAL EQUITY			
Equity attributable to owners of the Company			
Share capital	26	61	60
Share premium		239,191	236,046
Reserves		129,606	130,118
Accumulated losses		(283,933)	(260,459)
Attributable to owners of the Company		**84,925**	**105,765**
Non-controlling interest		**41,915**	**35,828**
TOTAL EQUITY		**126,840**	**141,593**
LIABILITIES			
NON CURRENT LIABILITIES			
Borrowings	27	418,540	319,389
Provisions and other long-term liabilities	28	46,284	42,509
Deferred income tax liability	18	2,286	2,770
Trade and other payables	29	25,921	34,766
TOTAL NON CURRENT LIABILITIES		**493,031**	**399,434**
CURRENT LIABILITIES			
Borrowings	27	7,664	39,283
Derivative financial instrument liabilities	25	19,289	3,067
Current income tax liabilities		42,942	5,155
Trade and other payables	29	96,397	52,008
TOTAL CURRENT LIABILITIES		**166,292**	**99,513**
TOTAL LIABILITIES		**659,323**	**498,947**
TOTAL EQUITY AND LIABILITIES		**786,163**	**640,540**

The Consolidated Financial Statements were approved by the Board of Directors on 7 March 2018.

The notes on pages 8 to 80 are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

	Attributable to owners of the Company						
Amount in US$ '000	Share Capital	Share Premium	Other Reserve	Translation Reserve	(Accumulated Losses) Retained Earnings	Non-controlling Interest	Total
Equity at 1 January 2015	**58**	**210,886**	**127,527**	**(3,510)**	**40,596**	**103,569**	**479,126**
Comprehensive income:							
Loss for the year	-	-	-	-	(234,031)	(50,535)	(284,566)
Currency translation differences	-	-	-	(1,001)	-	-	(1,001)
Total Comprehensive loss for the year 2015	**-**	**-**	**-**	**(1,001)**	**(234,031)**	**(50,535)**	**(285,567)**
Transactions with owners:							
Share-based payment (Note 30)	1	22,734	-	-	(14,993)	481	8,223
Repurchase of shares (Note 26)	-	(1,615)	-	-	-	-	(1,615)
Total 2015	**1**	**21,119**	**-**	**-**	**(14,993)**	**481**	**6,608**
Balances at 31 December 2015	**59**	**232,005**	**127,527**	**(4,511)**	**(208,428)**	**53,515**	**200,167**
Comprehensive income:							
Loss for the year	-	-	-	-	(49,092)	(11,554)	(60,646)
Currency translation differences	-	-	-	7,102	-	-	7,102
Total Comprehensive loss for the year 2016	**-**	**-**	**-**	**7,102**	**(49,092)**	**(11,554)**	**(53,544)**
Transactions with owners:							
Share-based payment (Note 30)	1	6,032	-	-	(2,939)	273	3,367
Repurchase of shares (Note 26)		(1,991)	-	-	-	-	(1,991)
Dividends distribution to non-controlling interest	-	-	-	-	-	(6,406)	(6,406)
Total 2016	**1**	**4,041**	**-**	**-**	**(2,939)**	**(6,133)**	**(5,030)**
Balances at 31 December 2016	**60**	**236,046**	**127,527**	**2,591**	**(260,459)**	**35,828**	**141,593**
Comprehensive income:							
Loss for the year	-	-	-	-	(24,228)	6,391	(17,837)
Currency translation differences	-	-	-	(512)	-	-	(512)
Total Comprehensive loss for the year 2017	**-**	**-**	**-**	**(512)**	**(24,228)**	**6,391**	**(18,349)**
Transactions with owners:							
Share-based payment (Note 30)	1	3,145	-	-	754	175	4,075
Dividends distribution to non-controlling interest	-	-	-	-	-	(479)	(479)
Total 2017	**1**	**3,145**	**-**	**-**	**754**	**(304)**	**3,596**
Balances at 31 December 2017	**61**	**239,191**	**127,527**	**2,079**	**(283,933)**	**41,915**	**126,840**

The notes on pages 8 to 80 are an integral part of these Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOW

Amounts in US$ '000	Note	2017	2016	2015
Cash flows from operating activities				
Loss for the year		(17,837)	(60,646)	(284,566)
Adjustments for:				
Income tax expense (benefit)	17	43,145	11,804	(17,054)
Depreciation		74,885	75,774	105,557
Loss on disposal of property, plant and equipment		190	14	2,000
Impairment loss (reversed) recognised for non-financial assets	20-36	-	(5,664)	149,574
Write-off of unsuccessful exploration efforts	20	5,834	31,366	30,084
Accrual of borrowing's interests		28,879	27,940	28,460
Borrowings cancellation costs	15	17,575	-	-
Amortisation of other long-term liabilities	28	(657)	(2,924)	(703)
Unwinding of long-term liabilities	28	2,779	2,693	2,575
Accrual of share-based payment		4,075	3,367	8,223
Foreign exchange loss (gain)		2,193	(13,872)	33,474
Unrealized loss on commodity risk management contracts	8	13,300	3,068	-
Income tax paid		(6,925)	(1,956)	(7,625)
Changes in working capital	5	(25,278)	11,920	(24,104)
Cash flows from operating activities – net		**142,158**	**82,884**	**25,895**
Cash flows from investing activities				
Purchase of property, plant and equipment		(105,604)	(39,306)	(48,842)
Cash flows used in investing activities – net		**(105,604)**	**(39,306)**	**(48,842)**
Cash flows from financing activities				
Proceeds from borrowings		425,000	186	7,036
Debt issuance costs paid		(6,683)	-	-
Proceeds from cash calls from related parties		1,155	5,210	2,400
Repurchase of shares		-	(1,991)	(1,615)
Principal paid		(355,022)	(22,645)	(89)
Interest paid		(27,688)	(25,490)	(25,754)
Borrowings cancellation costs paid		(12,315)	-	-
Dividends distribution to non-controlling interest		(479)	(6,406)	-
Cash flows from (used in) financing activities - net		**23,968**	**(51,136)**	**(18,022)**
Net increase (decrease) in cash and cash equivalents		**60,522**	**(7,558)**	**(40,969)**
Cash and cash equivalents at 1 January		73,563	82,730	127,672
Currency translation differences		670	(1,609)	(3,973)
Cash and cash equivalents at the end of the year		**134,755**	**73,563**	**82,730**
Ending Cash and cash equivalents are specified as follows:				
Cash in bank and bank deposits		134,734	73,551	82,720
Cash in hand		21	12	10
Cash and cash equivalents		**134,755**	**73,563**	**82,730**

The notes on pages 8 to 80 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 Cumberland House, 9th Floor, 1 Victoria 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 Chile, Colombia, Brazil, Peru and Argentina.

These Consolidated Financial Statements were authorised for issue by the Board of Directors on 7 March 2018.

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 convention.

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.

Note

2 Summary of significant accounting policies (continued)

2.1 Basis of preparation (continued)

2.1.1 Changes in accounting policy and disclosure

New and amended standards adopted by the Group

The following standards have been adopted by the Group for the first time for the financial year beginning on or after 1 January 2017:

- Recognition of Deferred Tax Assets for Unrealised Losses – Amendments to IAS 12
- Disclosure initiative – Amendments to IAS 7

The adoption of these amendments did not have any impact on the current period or any prior period and is not likely to affect future periods.

New standards, amendments and interpretations issued but not effective for the financial year beginning 1 January 2017 and not early adopted.

- IFRS 2 Share based payments: amended in June 2016 to clarify the measurement basis for cash-settled share-based payments and the accounting for modifications that change an award from cash-settled to equity-settled. It also introduces an exception to IFRS 2 principles by requiring an award to be treated as if it was wholly equity-settled, where an employer is obliged to withhold an amount for the employee's tax obligation associated with a share-based payment and pay that amount to the tax authority. It is effective for annual periods beginning on or after January 1, 2018. The Group estimates that these amendments will not have a material impact on the Group's operating results or financial position.

- IFRS 9 Financial Instruments and associated amendments to various other standards: IFRS 9 replaces the multiple classification and measurement models in IAS 39. Classification of debt assets will be driven by the entity's business model for managing the financial assets and the contractual cash flow characteristics of the financial assets. A debt instrument is measured at amortised cost if: a) the objective of the business model is to hold the financial asset for the collection of the contractual cash flows, and b) the contractual cash flows under the instrument solely represent payments of principal and interest. All other debt and equity instruments, including investments in complex debt instruments and equity investments, must be recognised at fair value.

All fair value movements on financial assets are taken through the statement of profit or loss, except for equity investments that are not held for trading, which may be recorded in the statement of profit or loss or in reserves (without subsequent recycling to profit or loss). For financial liabilities that are measured under the fair value option entities will need to recognise the part of the fair value change that is due to changes in their own credit risk in other comprehensive income rather than profit or loss.

The new hedge accounting rules (released in December 2013) align hedge accounting more closely with common risk management practices. As a general rule, it will be easier to apply hedge accounting going forward.

Note

2 Summary of significant accounting policies (continued)

2.1 Basis of preparation (continued)

2.1.1 Changes in accounting policy and disclosure (continued)

The new impairment model under IFRS 9 requires the recognition of impairment provisions based on expected credit losses rather than only incurred credit losses as is the case under IAS 39. It applies to financial assets classified at amortised cost, debt instruments measured at fair value through other comprehensive income, contract assets under IFRS 15, lease receivables, loan commitments and certain financial guarantee contracts.

The new standard also introduces expanded disclosure requirements and changes in presentation.

Management has assessed the effects of applying the new standard on the Group's Consolidated Financial Statements and concluded that no material impact will be expected.

- IFRS 15 Revenue from contracts with customers and associated amendments to various other standards: The IASB has issued a new standard for the recognition of revenue. This will replace IAS 18 which covers contracts for goods and services and IAS 11 which covers construction contracts. The new standard is based on the principle that revenue is recognised when control of a good or service transfers to a customer so the notion of control replaces the existing notion of risks and rewards.

These accounting changes may have flow-on effects on the entity's business practices regarding systems, processes and controls, compensation and bonus plans, contracts, tax planning and investor communications. Entities will have a choice of full retrospective application, or prospective application with additional disclosures.

It is mandatory for financial years commencing on or after 1 January 2018. The Group intends to adopt the standard using the modified retrospective approach which means that the cumulative impact of the adoption will be recognised in retained earnings as of 1 January 2018 and that comparatives will not be restated.

Management has assessed the effects of applying the new standard on the Group's Consolidated Financial Statements and concluded that no material impact will be expected.

- IFRS 16 Leases: will affect primarily the accounting by lessees and will result in the recognition of almost all leases on balance sheet. The standard removes the current distinction between operating and financing leases and requires recognition of an asset (the right to use the leased item) and a financial liability to pay rentals for virtually all lease contracts. An optional exemption exists for short-term and low-value leases. The accounting by lessors will not significantly change. Some differences may arise as a result of the new guidance on the definition of a lease.

The Group has not yet determined to what extent its commitments will result in the recognition of an asset and a liability for future payments and how this will affect the Group's profit and classification of cash flows. Some of the commitments may be covered by the exception for short-term and low-value leases and some commitments may relate to arrangements that will not qualify as leases under IFRS 16. At this stage, the Group does not intend to adopt the standard before its effective date. The Group intends to apply the simplified transition approach and will not restate comparative amounts for the year prior to first adoption.

Note

2 Summary of significant accounting policies (continued)

2.1 Basis of preparation (continued)

2.1.1 Changes in accounting policy and disclosure (continued)

- IFRIC 22 Foreign Currency Transactions and Advance Consideration: issued in December 2016. The interpretation addresses how to determine the date of the transaction for the purpose of determining the exchange rate to use on initial recognition of the related asset, expense or income related to an entity that has received or paid an advance consideration in a foreign currency. The date of the transaction is the date on which an entity initially rec-ognises the non-monetary asset or non-monetary liability arising from the payment or receipt of advance consid-eration. It is effective for annual periods beginning on January 1, 2018. The Group estimates that these interpreta-tions will not have a material impact on the Group's operating results or financial position.

- Sale or contribution of assets between an investor and its associate or joint venture – Amendments to IFRS 10 and IAS 28: The amendments clarify the accounting treatment for sales or contribution of assets between an investor and its associates or joint ventures.

- Improvements to IFRSs – 2014-2016 Cycle: amendments issued in December 2016 that are effective for periods beginning on or after January 1, 2018. The Group estimates that these amendments will not have an impact on the Group's operating results or financial position.

There are no other standards that are not yet effective and that would be expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

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 forecast 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 macroeconomic environment conditions, the performance of the operations, the US$ 425,000,000 debt fund raising completed in September 2017, the Group's cash position, and the fact that over 99% of its total indebtedness maturing in 2024, the Directors have formed a judgement, at the time of approving the 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.

Note

2 Summary of significant accounting policies (continued)

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.

The Group applies the acquisition method to account for business combinations. The consideration transferred for the acquisition of a subsidiary is the fair value of the assets transferred, the liabilities incurred by the former owners of the acquiree and the equity interests issued by the Group. The consideration transferred includes the fair value of any asset or liability resulting from a contingent consideration arrangement. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. Acquisition-related costs are expensed as incurred.

The excess of the consideration transferred, the amount of any non-controlling interest in the acquired entity, and the acquisition-date fair value of any previous equity interest in the acquired entity over the fair value of the identifiable net assets acquired is recorded as goodwill. If the total of consideration transferred, non-controlling interest recognised and previously held interest measured is less than the fair value of the net assets of the subsidiary acquired in the case of a bargain purchase, the difference is recognised directly in the income statement.

Intercompany transactions, balances and unrealised gains on transactions between the Group and its subsidiaries are eliminated. Unrealised 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 CEO, COO, CFO and managers in charge of the Geoscience, Operations, Corporate Governance, Finance and People departments. 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.

Note

2 Summary of significant accounting policies (continued)

2.5 Foreign currency translation

a) Functional and presentation currency

The Consolidated Financial Statements are presented in US Dollars, which is the Group's presentation currency.

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The functional currency of Group companies incorporated in Chile, Colombia, Peru and Argentina is the US Dollar, meanwhile for the Group´s Brazilian company the functional currency is the local currency, which is the Brazilian Real.

b) 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 recognised in the Consolidated Statement of 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 financial statements.

2.7 Revenue recognition

Revenue from the sale of crude oil and gas is recognised in the Consolidated Statement of Income when risk is transferred to the purchaser, and if the revenue can be measured reliably and is expected to be received. 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 32 (a).

Note

2 Summary of significant accounting policies (continued)

2.8 Production and operating costs

Production costs include wages and salaries incurred to achieve the revenue for the year. Direct and indirect costs of raw materials and consumables, rentals, leasing and royalties are also included within this account.

2.9 Financial results

Financial results include interest expenses, interest income, bank charges, the amortisation of financial assets and liabilities, and foreign exchanges gain and losses. The Group has capitalised borrowing cost for wells and facilities that were initiated after 1 January 2009. The capitalisation rate used to determine the amount of borrowing costs to be capitalised is the weighted average interest rate applicable to the Group's general borrowings during the year, which was 6.90% at year end 2017 (7.98% at year end 2016 and 2015). Amounts capitalised during the year amounted to US$ 610,841 (US$ 254,950 in 2016 and US$ 637,390 in 2015).

2.10 Property, plant and equipment

Property, plant and equipment are stated at historical cost less depreciation and impairment charge, 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, capitalising 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 labour costs and drilling costs of exploratory wells. No depreciation and/or amortisation 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 found 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$ 5,834,000 has been recognised in the Consolidated Statement of Income within Write-off of unsuccessful exploration efforts (US$ 31,366,000 in 2016 and US$ 30,084,000 in 2015). See Note 20.

All field development costs are considered construction in progress until they are finished and capitalised 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.

Note

2 Summary of significant accounting policies (continued)

2.10 Property, plant and equipment (continued)

Workovers of wells made to develop reserves and/or increase production are capitalised as development costs. Maintenance costs are charged to the Consolidated Statement of Income when incurred.

Capitalised 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 reserves. The calculation of the "unit of production" depreciation takes into account estimated future finding and development costs and is based on current year end unescalated price levels. Changes in reserves and cost estimates are recognised 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 up 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 2.12).

2.11 Provisions and other long-term liabilities

Provisions for asset retirement obligations, deferred income, restructuring obligations and legal claims are recognised when the Group has a present legal or constructive obligation as a result of past events; it is probable that an outflow of resources will be required to settle the obligation; and the amount has been reliably estimated. Restructuring provisions comprise lease termination penalties and employee 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 recognised as financial expense.

Note

2 Summary of significant accounting policies (continued)

2.11 Provisions and other long-term liabilities (continued)

2.11.1 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 capitalises 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 capitalised cost is depreciated over the estimated useful life of the related asset. According to interpretations and 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 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.

2.11.2 Deferred Income

Relates to contributions received in cash from the Group's clients to improve the project economics of gas wells. The amounts collected are reflected as a deferred income in the balance sheet and recognised in the Consolidated Statement of Income over the productive life of the associated wells. The depreciation of the gas wells that generated the deferred income is charged to the Consolidated Statement of Income simultaneously with the amortisation of the deferred income. The addition in 2016 and the amounts used in 2017 correspond to the deferred income related to the take or pay provision associated to gas sales in Brazil.

2.12 Impairment of non-financial assets

Assets that are not subject to depreciation and/or amortisation (i.e.: exploration and evaluation assets) are tested annually for impairment. Assets that are subject to depreciation and/or amortisation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

An impairment loss is recognised 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 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.

Note

2 Summary of significant accounting policies (continued)

2.12 Impairment of non-financial assets (continued)

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 2017, no impairment loss was recognised (impairment loss reversed for US$ 5,664,000 in 2016 and impairment loss recognised for US$ 149,574,000 in 2015). See Note 36. The write-offs are detailed in Note 20.

2.13 Lease contracts

All current lease contracts are considered to be operating leases on the basis that the lessor retains substantially all the risks and rewards related to the ownership of the leased asset. Payments related to operating leases and other rental agreements are recognised in the Consolidated Income Statement on a straight line basis over the term of the contract. The Group's total commitment relating to operating leases and rental agreements is disclosed in Note 32.

Leases in which substantially all of the risks and rewards of ownership are transferred to the lessee are classified as finance leases. Under a finance lease, the Group as lessor has to recognise an amount receivable equal to the aggregate of the minimum lease payments plus any unguaranteed residual value accruing to the lessor, discounted at the interest rate implicit in the lease.

2.14 Inventories

Inventories comprise crude oil and materials.

Crude oil is measured at the lower of cost and net realisable 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.

2.15 Current and deferred income tax

The tax expense for the year comprises current and deferred tax. Tax is recognised 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 balance sheet 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.

Note

2 Summary of significant accounting policies (continued)

2.15 Current and deferred income tax (continued)

Deferred income tax is recognised, 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 balance sheet date and are expected to apply when the related deferred income tax asset is realised or the deferred income tax liability is settled.

In addition, the Group has tax-loss carry-forwards in certain taxing jurisdictions that are available to be offset against future taxable profit. However, deferred tax assets are recognised 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 tax is recognised in respect of the retained earnings of overseas subsidiaries only if at the date of the statements of financial position, 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. In the event that these differences revert in total (e.g. dividends are declared and paid), the deferred tax liability which the Group would have to recognise amounts to approximately US$ 12,300,000.

Deferred tax balances are provided in full, with no discounting.

2.16 Financial assets

Financial assets are divided into the following categories: loans and receivables; financial assets at fair value through profit or loss; available-for-sale financial assets; and held-to-maturity investments. Financial assets are assigned to the different categories by management on initial recognition, depending on the purpose for which the investments were acquired. The designation of financial assets is re-evaluated at every reporting date at which a choice of classification or accounting treatment is available.

All financial assets are recognised when the Group becomes a party to the contractual provisions of the instrument.

All financial assets are initially recognised at fair value, plus transaction costs.

Note

2 Summary of significant accounting policies (continued)

2.16 Financial assets (continued)

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 recognised in the Consolidated Statement of Income when receivable, regardless of how the related carrying amount of financial assets is measured.

Loans and receivables 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. The Group's loans and receivables comprise trade receivables, prepayments and other receivables and cash and cash equivalents in the balance sheet. They arise when the Group provides money, goods or services directly to a debtor with no intention of trading the receivables. Loans and receivables are subsequently measured at amortised cost using the effective interest method, less provision for impairment. Any change in their value through impairment or reversal of impairment is recognised in the Consolidated Statement of Income. All of the Group's financial assets are classified as loan and receivables.

2.17 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 the security deposit granted in relation to the purchase of Argentinian assets (see Note 35) and short term investments with original maturities up to twelve months and over three months.

2.18 Impairment of financial assets

Provision against trade receivables is made when objective evidence is received that the Group will not be able to collect all amounts due to it in accordance with the original terms of those receivables. The amount of the write-down is determined as the difference between the asset's carrying amount and the present value of estimated future cash flows.

2.19 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, and bank overdrafts. Bank overdrafts, if any, are shown within borrowings in the current liabilities section of the Consolidated Statement of Financial Position.

Note

2 Summary of significant accounting policies (continued)

2.20 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 recognised initially at fair value and subsequently measured at amortised cost using the effective interest method.

2.21 Derivatives

Derivative financial instruments are recognised in the statement of financial position as assets or liabilities and initially and subsequently measured at fair value through profit and loss. 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 market-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. Gains and losses arising from changes in fair value are recognised in the Consolidated Statement of Income within Commodity risk management contracts.

For more information about derivatives please refer to Note 8.

2.22 Borrowings

Borrowings are obligations to pay cash and are recognised when the Group becomes a party to the contractual provisions of the instrument.

Borrowings are recognised initially at fair value, net of transaction costs incurred. Borrowings are subsequently stated at amortised cost; any difference between the proceeds (net of transaction costs) and the redemption value is recognised 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 accruals basis using the effective interest method.

Note

2 Summary of significant accounting policies (continued)

2.23 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 equity element attributable to shares granted according to IFRS 2 but not issued at year end or,
  - 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.
- "Translation reserve" representing the differences arising from translation of investments in overseas subsidiaries.
- "(Accumulated losses) Retained earnings" representing accumulated earnings and losses.

2.24 Share-based payment

The Group operates a number of equity-settled and cash-settled share-based compensation plans comprising share awards payments to certain employees and other third party contractors. Share-based payment transactions are measured in accordance with IFRS 2.

Fair value of the stock option plan for employee or contractors services received in exchange for the grant of the options is recognised as an expense. The total amount to be expensed over the vesting period is determined by reference to the fair value of the options granted calculated using the Geometric Brownian Motion method.

Non-market vesting conditions are included in assumptions about the number of options that are expected to vest. At each balance sheet date, the entity revises its estimates of the number of options that are expected to vest. It recognises the impact of the revision to original estimates, if any, in the Consolidated Statement of Income, with a corresponding adjustment to equity.

The fair value of the share awards payments is determined at the grant date by reference of the market value of the shares and recognised as an expense over the vesting period. 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 when the options are exercised.

For cash-settled share-based payment transactions, if any, the Company measures the services acquired for amounts that are based on the price of the Company's shares. The fair value of the liability incurred is measured using Geometric Brownian Motion method. Until the liability is settled, the Company is required to remeasure the fair value of the liability at each reporting date and at the date of settlement, with any changes in value recognised in profit or loss for the period.

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 management

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 Argentina, Colombia, Chile and Peru the functional currency is the US Dollar. The fluctuation of the local currencies of these countries against the US Dollar does not impact the loans, costs and revenue held in US Dollars; but it does impact the balances denominated in local currencies. Such is the case of the prepaid taxes.

In Chile, Colombia and Argentina subsidiaries most of the balances are denominated in US Dollars, and since it is the functional currency of the subsidiaries, there is no exposure to currency fluctuation except from receivables or payables originated in local currency mainly corresponding to VAT.

The Group minimises the local currency positions in Argentina, Colombia and Chile by seeking to equilibrate 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.

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 2017, the Argentine Peso devaluated by 17% (22% and 52% in 2016 and 2015) against the US Dollar, the Chilean Peso revaluated by 8% (revaluated by 6% in 2016 and devaluated by 16% in 2015) and the Colombian Peso revaluated by 1% (revaluated by 5% in 2016 and devaluated by 32% in 2015).

If the Argentine Peso, the Chilean Peso and the Colombian Peso had each devaluated an additional 10% against the US dollar, with all other variables held constant, post-tax loss for the year would have been higher by US$ 1,538,000 (US$ 2,683,400 in 2016 and US$ 1,003,300 in 2015).

Note

3 Financial Instruments-risk management (continued)

Currency risk (continued)

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 Itaú, which was fully repaid in September 2017, and intercompany loans. Most of the balances are denominated in Brazilian Real, and since it is the functional currency of the Brazilian subsidiary, there is no exposure to currency fluctuation except from the intercompany loan and the Itaú loan described in Note 27. The exchange loss generated by the Brazilian subsidiary during 2017 amounted to US$ 1,274,000 (gain of US$ 14,542,000 in 2016 and loss of US$ 35,605,000 in 2015).

During 2017, the Brazilian Real devaluated by 2% against the US Dollar (revaluated by 17% in 2016 and devaluated by 47% in 2015, respectively). If the Brazilian Real had devaluated 10% against the US dollar, with all other variables held constant, post-tax loss for the year would have been higher by US$ 3,100,000 (US$ 5,300,000 in 2016 and US$ 7,400,000 in 2015).

As of 31 December 2017, the balances denominated in the Peruvian local currency (Peruvian Soles) are not material.

As currency rate changes between the US Dollar and the local currencies, the Group recognises gains and losses in the Consolidated Statement of Income.

Price risk

The price realised for the oil produced by the Group is linked to US dollar denominated crude oil international benchmarks. The market price of these commodities is subject to significant volatility and has historically fluctuated widely in response to relatively minor changes in the global supply and demand for oil and natural gas, geopolitical landscape, economic conditions and a variety of additional factors.

In Colombia, the realised oil price is linked to the Vasconia crude reference price, a marker broadly used in the Llanos basin, adjusted for certain marketing and quality discounts based on, among other things, API, viscosity, sulphur content, water content, delivery point and transport costs.

In Chile, the oil price is based on 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 Gulf methanol spot barge prices, methanol spot Rotterdam prices and spot prices in Asia.

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.

Note

3 Financial Instruments-risk management (continued)

Price risk (continued)

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 loss for the year would have been higher by US$ 10,423,000 (US$ 23,655,000 in 2016 and US$ 23,940,000 in 2015).

As of October 2016, GeoPark considered it was appropriate to manage 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 recognised values. There is not considered to be any significant risk in respect of the Group's major customers and hedging counterparties.

In Colombia, during 2017, the Colombian subsidiary made 99% of the oil sales to Trafigura (one of the world's leading independent commodity trading and logistics houses), with Trafigura accounting for 79% of consolidated revenues for the same period.

All the oil produced in Chile as well as the gas produced by TdF Blocks (5% of total revenue, 10% in 2016 and 15% in 2015) is sold to ENAP, the State owned oil and gas company. In Chile, most of gas production is sold to the local subsidiary of Methanex, a Canadian public company (5% of consolidated revenue, 9% in 2016 and 7% in 2015).

In Brazil, all the hydrocarbons from Manati Field are sold to Petrobras, the State owned company, which is the operator of the Manati Field (10% of the consolidated revenue, 15% in 2016 and 2015).

The forementioned companies all have good credit standing and despite the concentration of the credit risk, the Directors do not consider there to be a significant collection risk.

In 2016 and 2017, the Group executed 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.

Note

3 Financial Instruments-risk management (continued)

Funding and Liquidity risk

In the past, the Group was able to raise capital through different sources of funding including equity, strategic partnerships and financial debt. During 2017, the Group placed US$ 425,000,000 notes (see Note 27).

The Group is positioned at the end of 2017 with a cash balance of US$ 134,755,000 and over 99% of its total indebtedness maturing in 2024. In addition, the Group has a large portfolio of attractive and largely discretional projects - both oil and gas - in multiple countries with over 31,000 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 indenture governing the Company Notes 2024 includes incurrence test covenants related to the 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 indenture governing the Notes. As of the date of these Consolidated Financial Statements, the Group is in compliance with all the indenture's provisions and covenants.

The most significant funding transactions executed in 2017, 2016 and 2015 include:

On September 2017, the Group successfully placed US$ 425,000,000 notes. These Notes carry a coupon of 6.50% per annum and their final maturity will be 21 September 2024. The net proceeds from the Notes were used by the Group to fully repay the 7.50% senior secured notes due 2020 and for general corporate purposes, including capital expenditures and repay other existing indebtedness.

On December 2015, the Group announced the execution of an offtake and prepayment agreement with Trafigura, one of its customers. The prepayment agreement provided GeoPark with access to up to US$ 100,000,000 in the form of prepaid future oil sales. The availability period for the prepayment agreement expired on 30 September 2017. Funds committed by Trafigura are being repaid by the Group through future oil deliveries over 2.5 years with a six-month grace period. As of the date of these Consolidated Financial Statements, outstanding balances related to the prepayment agreement amount to US$ 10,000,000.

Note

3 Financial Instruments-risk management (continued)

Interest rate risk

The Group's interest rate risk arises from long-term borrowings issued at variable rates, which expose the Group to cash flow to interest rate risk.

The Group does not face interest rate risk on its US$ 425,000,000 Notes which carry a fixed rate coupon of 6.50% per annum. As a consequence, the accruals and interest payment are no substantially affected to the market interest rate changes.

The Group analyses its interest rate exposure on a dynamic basis. Various scenarios are simulated taking into consideration refinancing, renewal of existing positions, alternative financing and hedging. Based on these scenarios, the Group calculates the impact on profit and loss of a defined interest rate shift. For each simulation, the same interest rate shift is used for all currencies. The scenarios are run only for liabilities that represent the major interest-bearing positions.

At 31 December 2017, the Group has no exposure to fluctuations in the interest rate, since its long-term borrowings were issued at fixed rate. At 31 December 2016 and 2015, if 1% had been added to interest rates on currency-denominated borrowings with all other variables held constant, post tax loss for the year would have been US$ 467,000 and US$ 507,000 higher, respectively.

Capital risk management

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 balance sheet) less cash and cash equivalents. Total capital is calculated as 'equity' as shown in the consolidated balance sheet plus net debt.

The Group's strategy is to keep the gearing ratio within a 30% to 45% range, in normal market conditions. Due to the market conditions prevailing during 2017 and 2016 and the growing strategy of the Group, the gearing ratio at year end is above such range.

Note

3 Financial Instruments-risk management (continued)

Capital risk management (continued)

The gearing ratios at 31 December 2017 and 2016 were as follows:

Amounts in US$ '000	2017	2016
Net Debt	291,449	285,109
Total Equity	126,840	141,593
Total Capital	418,289	426,702
Gearing Ratio	70%	67%

Note

4 Accounting estimates and assumptions

Estimates and assumptions are used in preparing the financial statements. Although these estimates are based on management's best knowledge of current events and actions, actual results may differ from them. 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:

- 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 own 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 will differ, management considers the assessment of impairment to be a critical accounting estimate (see Note 36).

  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 31 December 2017 prepared by DeGolyer and MacNaughton, an international consultancy to the oil and gas industry based in Dallas. It incorporates many factors and assumptions including:

Note

4 Accounting estimates and assumptions (continued)

- 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; 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.

- The Group adopts the successful efforts method of accounting. The Management of the Group makes assessments and estimates regarding whether an exploration asset should continue to be carried forward as an exploration and evaluation asset not yet determined or when insufficient information exists for this type of cost to remain as an asset. In making this assessment Management takes professional advice from qualified experts.

- Oil and gas assets held in property plant and equipment are mainly depreciated on a unit of production 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.

- 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 recognising 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 recognised are based upon estimated future abandonment costs, wells subject to abandonment, time to abandonment, and future inflation rates.

- 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 Management of the Group currently knows, it is not expected any material impact on the 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 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	2017	2016	2015
Increase in asset retirement obligation	5,943	1,195	985
Increase in provisions for other long-term liabilities	2,053	3,468	-
Purchase of property, plant and equipment	11,759	(4,657)	830

Changes in working capital shown in the Consolidated Statement of Cash Flow are disclosed as follows:

Amounts in US$ '000	2017	2016	2015
Increase in Prepaid taxes	(14,802)	(2,351)	(16,611)
(Increase) Decrease in Inventories	(2,031)	466	2,752
(Increase) Decrease in Trade receivables	(1,344)	(4,811)	22,470
(Increase) Decrease in Prepayments and other receivables and Other assets	(8,623)	(1,758)	405
Customer advance (repayments) payments	(10,000)	20,000	-
Security deposit granted (Note 35)	(15,600)	-	-
Increase (Decrease) in Trade and other payables	27,122	374	(33,120)
	(25,278)	**11,920**	**(24,104)**

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 CEO, COO, CFO and managers in charge of the Geoscience, Operations, Corporate Governance, Finance and People departments. 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 for the period before net finance cost, income tax, depreciation, amortization, certain non-cash items such as impairments and write-offs of unsuccessful efforts, accrual of share-based payment, unrealized result on commodity risk management contracts and other non recurring events. Operating Netback is equivalent to Adjusted EBITDA before cash expenses included in Administrative, Geological and Geophysical and Other operating expenses. Other information provided, except as noted below, to the Executive Committee is measured in a manner consistent with that in the financial statements.

Segment areas (geographical segments):

Amounts in US$ '000	Chile	Brazil	Colombia	Peru	Argentina	Corporate	Total
2017							
Revenue	**32,738**	**34,238**	**263,076**	**-**	**70**	**-**	**330,122**
Sale of crude oil	15,873	910	262,309	-	70	-	279,162
Sale of gas	16,865	33,328	767	-	-	-	50,960
Realized loss on commodity risk management contracts	-	-	(2,148)	-	-	-	**(2,148)**
Production and operating costs	(20,999)	(10,737)	(66,913)	-	(338)	-	**(98,987)**
Royalties	(1,314)	(3,134)	(24,236)	-	(13)	-	(28,697)
Transportation costs	(1,211)	-	(1,678)	-	(80)	-	(2,969)
Share-based payment	(170)	(39)	(248)	-	-	-	(457)
Other costs	(18,304)	(7,564)	(40,751)	-	(245)	-	(66,864)
Operating (loss) profit	**(19,675)**	**4,434**	**116,290**	**(3,850)**	**(3,430)**	**(14,773)**	**78,996**
Operating netback	**11,222**	**23,540**	**194,013**	**-**	**(467)**	**-**	**228,308**
Adjusted EBITDA	**4,070**	**20,166**	**168,303**	**(3,505)**	**(2,183)**	**(11,075)**	**175,776**
Depreciation	(23,730)	(10,809)	(40,010)	(139)	(159)	(38)	(74,885)
Write-off	(546)	(2,978)	(1,625)	-	(685)	-	(5,834)
Total assets	301,931	91,604	288,429	22,099	30,924	51,176	786,163
Employees (average)	102	12	164	13	88	-	379
Employees at year end	102	12	180	19	92	-	405

Note

6 Segment information (continued)

Amounts in US$ '000	Chile	Brazil	Colombia	Peru	Argentina	Corporate	Total
2016							
Revenue	**36,723**	**29,719**	**126,228**	**-**	**-**	**-**	**192,670**
Sale of crude oil	18,774	688	125,731	-	-	-	145,193
Sale of gas	17,949	29,031	497	-	-	-	47,477
Realized gain on commodity risk management contracts	-	-	**514**	-	-	-	**514**
Production and operating costs	**(22,169)**	**(8,459)**	**(36,607)**	**-**	**-**	**-**	**(67,235)**
Royalties	(1,495)	(2,721)	(7,281)	-	-	-	(11,497)
Transportation costs	(1,170)	-	(1,111)	-	-	-	(2,281)
Share-based payment	(138)	(71)	(413)	-	-	-	(622)
Other costs	(19,366)	(5,667)	(27,802)	-	-	-	(52,835)
Operating (loss) profit	**(44,969)**	**(645)**	**31,463**	**(3,147)**	**370**	**(11,685)**	**(28,613)**
Operating netback	**13,696**	**21,356**	**87,523**	**41**	**(378)**	**(91)**	**122,147**
Adjusted EBITDA	**5,159**	**17,487**	**66,921**	**(2,607)**	**1,848**	**(10,487)**	**78,321**
Depreciation	(31,355)	(12,974)	(31,148)	(130)	(150)	(17)	(75,774)
Reversal of impairment losses	-	-	5,664	-	-	-	5,664
Write-off	(19,389)	(4,583)	(7,394)	-	-	-	(31,366)
Total assets	317,969	99,904	182,784	5,020	6,071	28,792	640,540
Employees (average)	102	10	138	11	80	-	341
Employees at year end	102	10	146	10	77	-	345

Amounts in US$ '000	Chile	Brazil	Colombia	Peru	Argentina	Corporate	Total
2015							
Revenue	**44,808**	**32,388**	**131,897**	**-**	**597**	**-**	**209,690**
Sale of crude oil	29,180	955	131,897	-	597	-	162,629
Sale of gas	15,628	31,433	-	-	-	-	47,061
Production costs	**(28,704)**	**(8,056)**	**(48,534)**	**-**	**(1,448)**	**-**	**(86,742)**
Royalties	(1,973)	(2,998)	(8,150)	-	(34)	-	(13,155)
Transportation costs	(2,441)	-	(2,068)	-	(2)	-	(4,511)
Share-based payment	(132)	-	(234)	-	(197)	-	(563)
Other costs	(24,158)	(5,058)	(38,082)	-	(1,215)	-	(68,513)
Operating (loss) profit	**(180,264)**	**6,639**	**(37,227)**	**(6,719)**	**(2,350)**	**(12,570)**	**(232,491)**
Operating netback	**15,254**	**24,393**	**80,355**	**44**	**(1,732)**	**(287)**	**118,027**
Adjusted EBITDA	**(183)**	**20,460**	**66,736**	**(6,520)**	**(684)**	**(6,022)**	**73,787**
Depreciation	(39,227)	(13,568)	(52,434)	(129)	(199)	-	(105,557)
Impairment loss	(104,515)	-	(45,059)	-	-	-	(149,574)
Write-off	(25,751)	-	(4,333)	-	-	-	(30,084)
Total assets	381,143	114,974	153,071	4,287	3,181	47,143	703,799
Employees (average)	153	11	130	16	93	-	403
Employees at year end	106	12	133	11	90	-	352

Approximately 76% of capital expenditure was incurred by Colombia (67% in 2016 and 66% in 2015), 10% was incurred by Chile (20% in 2016 and 22% in 2015), 8% was incurred by Argentina (4% in 2016 and nil in 2015), 3% was incurred by Brazil (9% in 2016 and 12% in 2015) and 3% was incurred by Peru (nil in 2016 and 2015).

Note

6 Segment information (continued)

A reconciliation of total Operating netback to total profit (loss) before income tax is provided as follows:

Amounts in US$ '000	2017	2016	2015
Operating netback	**228,308**	**122,147**	**118,027**
Administrative expenses	(38,937)	(32,323)	(30,590)
Geological and geophysical expenses	(13,595)	(11,503)	(13,650)
Adjusted EBITDA for reportable segments	**175,776**	**78,321**	**73,787**
Unrealized loss on commodity risk management contracts	(13,300)	(3,068)	-
Depreciation [(a)]	(74,885)	(75,774)	(105,557)
Share-based payment	(4,075)	(3,367)	(8,223)
Impairment and write-off of unsuccessful exploration efforts	(5,834)	(25,702)	(179,658)
Others [(b)]	1,314	977	(12,840)
Operating profit (loss)	**78,996**	**(28,613)**	**(232,491)**
Financial expenses	(53,511)	(36,229)	(36,924)
Financial income	2,016	2,128	1,269
Foreign exchange (loss) profit	(2,193)	13,872	(33,474)
Profit (Loss) before tax	**25,308**	**(48,842)**	**(301,620)**

(a) Net of capitalised costs for oil stock included in Inventories.

(b) In 2015 includes termination costs (see Note 36). Also includes internally capitalised costs.

Note

7 Revenue

Amounts in US$ '000	2017	2016	2015
Sale of crude oil	279,162	145,193	162,629
Sale of gas	50,960	47,477	47,061
	330,122	**192,670**	**209,690**

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 or zero-premium 3 ways (put spread plus call), 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 are accounted for as non-hedge derivatives as of 31 December 2017 and therefore all changes in the fair values of its derivative contracts are recognised as gains or losses in the results of the periods in which they occur.

Note

8 Commodity risk management contracts (continued)

The following table presents the Group's derivative contracts in force as of 31 December 2017:

Period	Reference	Type	Volume bbl/d	Price US$/bbl
1 October 2017 - 31 March 2018	ICE BRENT	Zero Premium Collar	4,000	50.00 Put 54.90 Call
1 October 2017 - 31 March 2018	ICE BRENT	Zero Premium Collar	2,000	50.00 Put 54.95 Call
1 January 2018 - 30 June 2018	ICE BRENT	Zero Premium Collar	2,000	52.00 Put 60.00 Call
1 January 2018 - 30 June 2018	ICE BRENT	Zero Premium Collar	1,000	52.00 Put 58.40 Call
1 April 2018 - 30 June 2018	ICE BRENT	Zero Premium Collar	2,000	52.00 Put 58.25 Call
1 January 2018 - 30 June 2018	ICE BRENT	Zero Premium 3 Way	1,000	42.00-52.00 Put 59.55 Call
1 January 2018 - 30 June 2018	ICE BRENT	Zero Premium 3 Way	1,000	42.00-52.00 Put 59.50 Call
1 April 2018 - 30 June 2018	ICE BRENT	Zero Premium 3 Way	1,000	42.00-52.00 Put 59.60 Call
1 January 2018 - 30 June 2018	ICE BRENT	Zero Premium 3 Way	2,000	43.00-53.00 Put 64.55 Call
1 July 2018 - 30 September 2018	ICE BRENT	Zero Premium 3 Way	5,000	43.00-53.00 Put 69.00 Call

The table below summarizes the gain (loss) on the commodity risk management contracts:

	2017	2016	2015
Realized (loss) gain on commodity risk management contracts	(2,148)	514	-
Unrealized loss on commodity risk management contracts	(13,300)	(3,068)	-
Total	**(15,448)**	**(2,554)**	**-**

Note

9 Production and operating costs

Amounts in US$ '000	2017	2016	2015
Well and facilities maintenance	14,722	13,160	19,974
Staff costs (Note 11)	15,017	10,859	17,999
Share-based payment (Notes 11)	457	622	563
Royalties	28,697	11,497	13,155
Consumables	11,902	8,283	8,591
Transportation costs	2,969	2,281	4,511
Equipment rental	5,818	3,868	3,517
Safety and Insurance costs	2,591	2,222	3,239
Gas plant costs	6,069	6,300	2,878
Field camp	2,377	1,687	2,645
Non operated blocks costs	1,213	1,082	2,127
Other costs	7,155	5,374	7,543
	98,987	**67,235**	**86,742**

Note

10 Depreciation

Amounts in US$ '000	2017	2016	2015
Oil and gas properties	57,725	61,080	84,849
Production facilities and machinery	14,558	10,788	15,467
Furniture, equipment and vehicles	1,948	2,702	2,850
Buildings and improvements	844	920	874
Depreciation of property, plant and equipment [(a)]	**75,075**	**75,490**	**104,040**

Related to:			
Productive assets	72,283	71,868	100,316
Administrative assets	2,792	3,622	3,724
Depreciation total [(a)]	**75,075**	**75,490**	**104,040**

[(a)] Depreciation without considering capitalised costs for oil stock included in Inventories.

Note

11 Staff costs and Directors Remuneration

	2017	2016	2015
Number of employees at year end	405	345	352
Amounts in US$ '000			
Wages and salaries	44,891	36,059	40,574
Share-based payments (Note 30)	4,075	3,367	8,223
Social security charges	5,364	3,792	6,197
Director's fees and allowance	3,458	2,088	1,238
	57,788	**45,306**	**56,232**

Recognised as follows:			
Production and operating costs	15,474	11,481	18,562
Geological and geophysical expenses	11,026	10,439	11,336
Administrative expenses	31,288	23,386	26,334
	57,788	**45,306**	**56,232**

Board of Directors' and key managers' remuneration			
Salaries and fees	9,674	7,337	6,549
Share-based payments	2,322	1,211	6,544
Other benefits in kind	287	112	167
	12,283	**8,660**	**13,260**

Note

11 Staff costs and Directors Remuneration (continued)

Directors' Remuneration

	Executive Directors' Fees	Executive Directors' Bonus	Non-Executive Directors' Fees (in US$)	Director Fees Paid in Shares (No. of Shares)	Cash Equivalent Total Remuneration
Gerald O'Shaughnessy	US$ 400,000	-	-	-	US$ 400,000
James F. Park	US$ 800,000	US$ 800,000	-	-	US$ 1,600,000
Pedro Aylwin [(a)]	-	-	-	-	-
Peter Ryalls [(b)]	-	-	US$ 115,000	9,388	US$ 165,010
Juan Cristóbal Pavez [(c)]	-	-	US$ 110,000	15,408	US$ 210,020
Carlos Gulisano	-	-	US$ 110,000	15,408	US$ 210,020
Robert Bedingfield [(d)]	-	-	US$ 102,500	15,408	US$ 202,520
Michael Dingman	-	-	US$ 46,667	8,853	US$ 105,012
Jamie Coulter	-	-	US$ 50,000	8,015	US$ 112,519

[a] Pedro Aylwin has a service contract that provides for him to act as Manager of Corporate Governance so he resigned his fees as Director.

[b] Technical Committee Chairman until his death. Afterwards the Chairman is Carlos Gulisano.

[c] Compensation Committee Chairman.

[d] Audit Committee Chairman.

The non-executive Directors annual fees correspond to US$ 80,000 to be settled in cash and US$ 100,000 to be settled in stocks, paid quarterly in equal installments. In the event that a non-executive Director serves as Chairman of any Board Committees, an additional annual fee of US$ 20,000 shall apply. A Director who serves as a member of any Board Committees shall receive an annual fee of US$ 10,000. Total payment due shall be calculated in an aggregate basis for Directors serving in more than one Committee. The Chairman fee shall not be added to the member's fee for the same Committee. Payments of Chairmen and Committee members' fees shall be made quarterly in arrears and settled in cash only.

Note

12 Geological and geophysical expenses

Amounts in US$ '000	2017	2016	2015
Staff costs (Note 11)	10,525	9,541	10,557
Share-based payment (Notes 11)	501	898	779
Allocation to capitalised project	(6,402)	(2,119)	(598)
Other services	3,070	1,962	3,093
	7,694	**10,282**	**13,831**

Note

13 Administrative expenses

Amounts in US$ '000	2017	2016	2015
Staff costs (Note 11)	24,713	19,451	18,215
Share-based payment (Notes 11)	3,117	1,847	6,881
Consultant fees	5,120	3,894	4,115
Office expenses	2,506	2,217	2,535
Travel expenses	2,772	1,717	1,497
Director's fees and allowance (Note 11)	3,458	2,088	1,238
Communication and IT costs	2,109	2,013	1,791
Allocation to joint operations	(7,646)	(4,365)	(4,203)
Other administrative expenses	5,905	5,308	5,402
	42,054	**34,170**	**37,471**

Note

14 Selling expenses

Amounts in US$ '000	2017	2016	2015
Transportation	864	3,559	4,760
Selling taxes and other	272	663	451
	1,136	**4,222**	**5,211**

Note

15 Financial results

Amounts in US$ '000	2017	2016	2015
Financial expenses			
Interest and amortisation of debt issue costs	(27,823)	(28,984)	(28,983)
Interest with related parties	(2,224)	(1,587)	(1,560)
Less: amounts capitalised on qualifying assets	611	255	637
Borrowings cancellation costs	(17,575)	-	-
Bank charges and other financial results	(3,721)	(3,220)	(4,443)
Unwinding of long-term liabilities (Note 28)	(2,779)	(2,693)	(2,575)
	(53,511)	**(36,229)**	**(36,924)**
Financial income			
Interest received	2,016	2,128	1,269
	2,016	**2,128**	**1,269**
Foreign exchange gains and losses			
Foreign exchange (loss) gain	(2,193)	13,872	(33,474)
	(2,193)	**13,872**	**(33,474)**
Total Financial results	**(53,688)**	**(20,229)**	**(69,129)**

Note

16 Tax reforms

Colombia

A tax reform has been enacted in Colombia during December 2016. The legislation included significant changes to certain corporate income tax and statutory income tax provisions, including rate reductions and the repeal of certain corporate-level taxes. The legislation also aimed to raise tax revenue mostly by increasing the rate of the value added tax (VAT) to 19% (from 16%) and through a variety of excise taxes. Most of the tax provisions were effective 1 January 2017.

The legislation also included the following provisions that are intended to simplify the corporate income tax system by:

- Eliminating the "CREE" tax on corporations and the CREE surtax (CREE is the Spanish acronym for the "fairness tax").
- Introducing a temporary income surtax of 6% for 2017 and 4% for 2018.

Accordingly, with this tax reform, the corporate income tax will have the following rate schedule (applied beyond a limited profit threshold):

- 40% in 2017 (34% income tax plus 6% income surtax)
- 37% in 2018 (33% income tax plus 4% income surtax)
- 33% in 2019 and onwards.

There is an increase in the tax rate on deemed income relating to increases in a taxpayer's net worth (i.e., the increase in the value of a taxpayer's assets); the rate is increased from 3% to 3.5%.

Other changes to the income tax law were the following:

- New withholding tax on dividends—with the applicable rates for non-resident shareholders of: (1) 5% for dividends distributed out of the distributing entity's previously taxed profits; and (2) 35% for dividends distributed out of the distributing entity's previously untaxed profits, plus an additional 5% after having applied and deducted the initial 35% withholding.
- A general 15% withholding tax rate for taxable income accrued by non-residents without a permanent establishment (certain special rates may apply).
- Lengthen the statute of limitations with respect to tax returns and assessments.
- Limit loss carryforwards to 12 years.
- Allow for a deduction of VAT paid on certain acquisitions or imports of capital goods when calculating the taxpayer's income tax liability.
- Retain the tax on long-term capital gains at 10% for both corporations and non-residents.

The legislation also revises and refines tax accounting standards based on IFRS rules.

Note

16 Tax reforms (Continued)

Argentina

A tax reform has been enacted in Argentina during December 2017. The legislation included significant changes to certain corporate income tax and statutory income tax provisions, including rate reductions. Most of the tax provisions are effective from fiscal year 2018.

With this tax reform, the corporate income tax -previously 35%- will have the following rate schedule:

- 30% in 2018 and 2019
- 25% in 2020 and 2021 and onwards.

Other changes include the following:

- New withholding tax on dividends—with the applicable rates for non-resident shareholders of: (1) 7% for dividends distributed out of the distributing entity's previously taxed profits of fiscal years 2018 and 2019; and (2) 13% for dividends distributed out of the distributing entity's previously taxed profits of fiscal years 2020 and onwards.
- Application of inflation adjustment for corporate tax purposes is reinstated under certain circumstances.
- Possible tax revaluation of investment in fixed assets, under payment of a special tax.
- Allow for short term recovery of VAT paid on acquisitions or imports of capital goods, when non recoverable with VAT on usual sales.

Note

17 Income tax

Amounts in US$ '000	2017	2016	2015
Current tax	(48,449)	(12,359)	(7,262)
Deferred income tax (Note 18)	5,304	555	24,316
	(43,145)	**(11,804)**	**17,054**

Note

17 Income tax (continued)

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	2017	2016	2015
Profit (Loss) before tax	25,308	(48,842)	(301,620)
Tax losses from non-taxable jurisdictions	22,708	12,318	15,852
Taxable profit (loss)	**48,016**	**(36,524)**	**(285,768)**
Income tax calculated at domestic tax rates applicable to Profit (Losses) Income in the respective countries	(31,107)	(809)	62,589
Tax losses where no deferred tax benefit is recognised	(8,111)	(6,616)	(16,325)
Effect of currency translation on tax base	(2,330)	(2,840)	(6,776)
Changes in the income tax rate (Note 16)	542	220	(625)
Non recoverable tax loss carry-forwards	-	-	(15,537)
Non-taxable results [(a)]	(2,139)	(1,759)	(6,272)
Income tax	**(43,145)**	**(11,804)**	**17,054**

(a) Includes non-deductible expenses in each jurisdiction and changes in the estimation of deferred tax assets and liabilities.

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 (Argentina, Brazil, Colombia, Peru and Chile) ranges from 15% to 40%.

The Group has significant tax losses available which can be utilised against future taxable profit in the following countries:

Amounts in US$ '000	2017	2016	2015
Argentina	4,849	2,908	3,834
Chile [(a)]	345,104	280,290	209,910
Brazil [(a)]	33,721	16,057	-
Total tax losses at 31 December	**383,674**	**299,255**	**213,744**

(a) Taxable losses have no expiration date.

Note

17 Income Tax (continued)

At the balance sheet date deferred tax assets in respect of tax losses in Argentina and in certain Companies in Chile have not been recognised as there is insufficient evidence of future taxable profits to offset them (in the case of Argentina, before the statute of limitation of these tax losses causes them to expire).

Expiring dates for tax losses accumulated at 31 December 2017 are:

Expiring date	Amounts in US$ '000
2020	754
2021	1,446
2022	2,649

Note

18 Deferred income tax

The gross movement on the deferred income tax account is as follows:

Amounts in US$ '000	2017	2016
Deferred tax at 1 January	20,283	17,691
Reclassification [a]	-	574
Currency translation differences	(237)	1,463
Income statement credit	5,304	555
Deferred tax at 31 December	**25,350**	**20,283**

[a] Corresponds to differences between income tax provision and the final tax return presented.

The breakdown and movement of deferred tax assets and liabilities as of 31 December 2017 and 2016 are as follows:

Amounts in US$ '000	At the beginning of year	Currency translation differences	(Charged) credited to net profit	At end of year
Deferred tax assets				
Difference in depreciation rates and other	19,225	(237)	(2,817)	16,171
Taxable losses	3,828	-	7,637	11,465
Total 2017	**23,053**	**(237)**	**4,820**	**27,636**
Total 2016	**34,646**	**1,463**	**(13,056)**	**23,053**

Note

18 Deferred income tax (continued)

Amounts in US$ '000	At the beginning of year	Credited to net profit	Reclassification [a]	At end of year
Deferred tax liabilities				
Difference in depreciation rates and other	(17,308)	(2,766)	-	(20,074)
Taxable losses	14,538	3,250	-	17,788
Total 2017	**(2,770)**	**484**	**-**	**(2,286)**
Total 2016	**(16,955)**	**13,611**	**574**	**(2,770)**

[a] Corresponds to differences between income tax provision and the final tax return presented.

Note

19 Earnings per share

Amounts in US$ '000 except for shares	2017	2016	2015
Numerator:			
Loss for the year attributable to owners	(24,228)	(49,092)	(234,031)
Denominator:			
Weighted average number of shares used in basic EPS	60,093,191	59,777,145	57,759,001
(Losses) after tax per share (US$) – basic	**(0.40)**	**(0.82)**	**(4.05)**

Amounts in US$ '000 except for shares	2017 [a]	2016	2015
Weighted average number of shares used in basic EPS	60,093,191	59,777,145	57,759,001
Effect of dilutive potential common shares [a]			
Weighted average number of common shares for the purposes of diluted earnings per shares	60,093,191	59,777,145	57,759,001
(Losses) after tax per share (US$) – diluted	**(0.40)**	**(0.82)**	**(4.05)**

[a] For the year ended 31 December 2017, there were 4,564,777 (1,390,706 in 2016 and 1,032,279 in 2015) of potential shares that could have a dilutive impact but were 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[b]	Total
Cost at 1 January 2015	**749,947**	**12,057**	**111,646**	**9,527**	**59,425**	**140,444**	**1,083,046**
Additions	(4,640)[a]	954	-	272	36,543	12,299	45,428
Currency translation differences	(27,522)	(182)	(2,577)	(92)	-	(1,510)	(31,883)
Disposals	(241)	(13)	(1,685)	(84)	-	-	(2,023)
Write-off / Impairment loss	(128,956)	-	(13,242)	-	(7,376)	(30,084) [c]	(179,658)
Transfers	60,404	929	30,690	895	(58,769)	(34,149)	-
Cost at 31 December 2015	**648,992**	**13,745**	**124,832**	**10,518**	**29,823**	**87,000**	**914,910**
Additions	(3,531) [a]	406	466	-	20,322	18,181	35,844
Currency translation differences	16,132	126	2,077	35	73	790	19,233
Disposals	-	(22)	-	-	-	-	(22)
Write-off / Impairment reversal	5,664	-	-	-	-	(31,366) [d]	(25,702)
Transfers	24,984	102	5,038	-	(17,292)	(12,832)	-
Cost at 31 December 2016	**692,241**	**14,357**	**132,413**	**10,553**	**32,926**	**61,773**	**944,263**
Additions	7,997 [a]	954	-	-	66,953	49,455	125,359
Currency translation differences	(1,142)	(12)	(147)	(3)	(62)	(104)	(1,470)
Disposals	-	(112)	-	(189)	-	-	(301)
Write-off / Impairment reversal	-	-	-	-	-	(5,834) [e]	(5,834)
Transfers	77,408	211	25,130	-	(61,827)	(40,922)	-
Cost at 31 December 2017	**776,504**	**15,398**	**157,396**	**10,361**	**37,990**	**64,368**	**1,062,017**
Depreciation and write-down at 1 January 2015	**(240,439)**	**(4,449)**	**(45,147)**	**(2,244)**	**-**	**-**	**(292,279)**
Depreciation	(84,849)	(2,850)	(15,467)	(874)	-	-	(104,040)
Disposals	-	8	-	15	-	-	23
Currency translation differences	4,115	(26)	-	(92)	-	-	3,997
Depreciation and write-down at 31 December 2015	**(321,173)**	**(7,317)**	**(60,614)**	**(3,195)**	**-**	**-**	**(392,299)**
Depreciation	(61,080)	(2,702)	(10,788)	(920)	-	-	(75,490)
Disposals	-	8	-	-	-	-	8
Currency translation differences	(2,486)	(38)	(296)	(16)	-	-	(2,836)
Depreciation and write-down at 31 December 2016	**(384,739)**	**(10,049)**	**(71,698)**	**(4,131)**	**-**	**-**	**(470,617)**
Depreciation	(57,725)	(1,948)	(14,558)	(844)	-	-	(75,075)
Disposals	-	73	-	38	-	-	111
Currency translation differences	930	8	24	5	-	-	967
Depreciation and write-down at 31 December 2017	**(441,534)**	**(11,916)**	**(86,232)**	**(4,932)**	**-**	**-**	**(544,614)**
Carrying amount at 31 December 2015	**327,819**	**6,428**	**64,218**	**7,323**	**29,823**	**87,000**	**522,611**
Carrying amount at 31 December 2016	**307,502**	**4,308**	**60,715**	**6,422**	**32,926**	**61,773**	**473,646**
Carrying amount at 31 December 2017	**334,970**	**3,482**	**71,164**	**5,429**	**37,990**	**64,368**	**517,403**

Note

20 Property, plant and equipment (continued)

(a) Corresponds to the effect of change in estimate of assets retirement obligations.

(b) Exploration wells movement and balances are shown in the table below; seismic and other exploratory assets amount to US$ 53,764,000 (US$ 53,523,000 in 2016 and US$ 64,094,000 in 2015).

Amounts in US$ '000	Total
Exploration wells at 31 December 2015	**22,906**
Additions	15,088
Write-offs	(19,949)
Transfers	(9,795)
Exploration wells at 31 December 2016	**8,250**
Additions	35,299
Write-offs	(3,664)
Transfers	(29,281)
Exploration wells at 31 December 2017	**10,604**

As of 31 December 2017, there were two exploratory wells that have been capitalised for a period less than a year amounting to US$ 4,488,000 and two exploratory wells that have been capitalised for a period over a year amounting to US$ 6,116,000.

(c) Corresponds to the cost of two unsuccessful exploratory wells in Colombia (one well in CPO4 Block and one well in Llanos 32). The charge also includes the loss generated by the write-off of the seismic cost for Flamenco Block in Chile generated by the relinquishment of 143 sq km in November 2015 and the write off of two wells drilled in previous years in the same block for which no additional work would be performed.

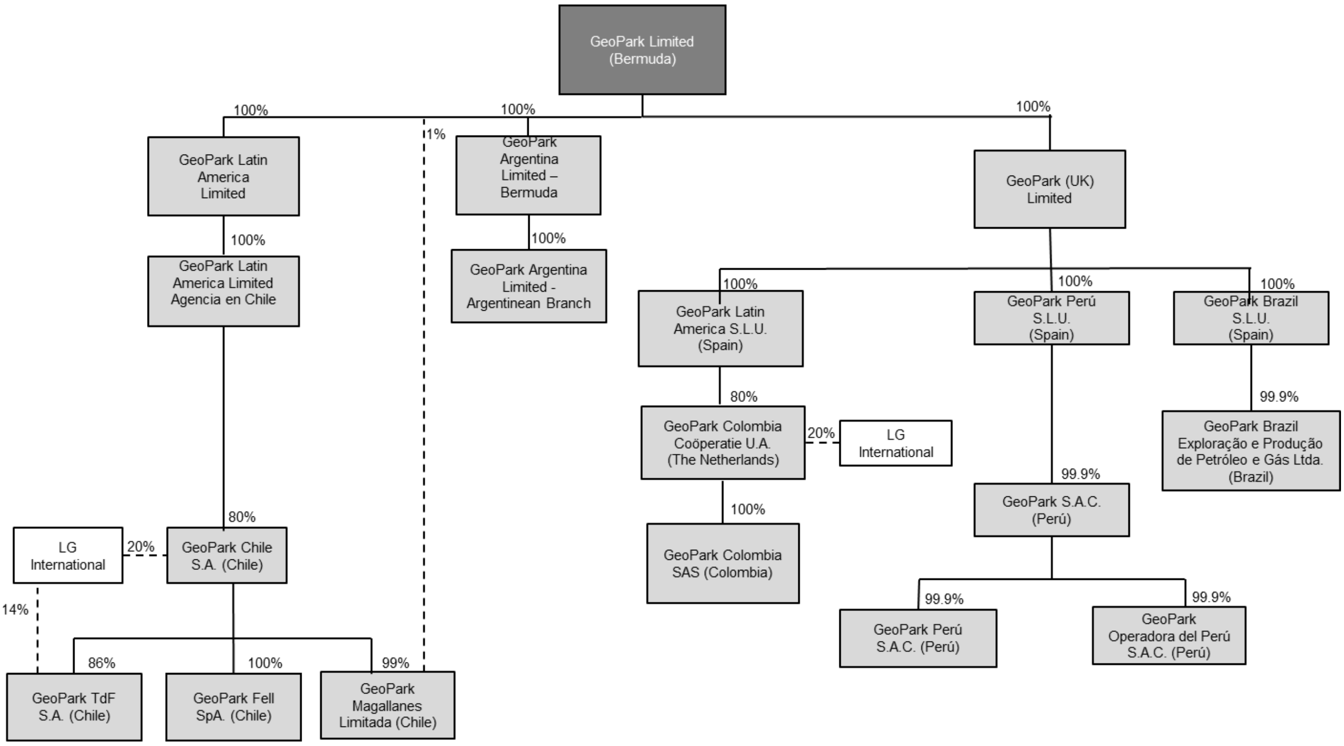
(d) Corresponds to the write-off of five wells drilled in previous years in the Chilean blocks for which no additional work would be performed, the loss generated by the write-off of the seismic cost for Llanos 62 Block in Colombia generated by the relinquishment of the area in September 2016. In addition, during September 2016, five blocks in Brazil were relinquished so the associated investment was written off.

(e) Corresponds to five unsuccessful exploratory wells, one well drilled in Colombia (Llanos 34 Block), one well drilled in Brazil (REC-T-94 Block) and three non-operated wells drilled in Argentina (Puelen and Sierra del Nevado Blocks) in 2017. The charge also includes the loss generated by the write-off of the seismic cost for Campanario and Isla Norte Blocks in Chile generated by the relinquishment of 327 sq km in 2017.

Note

21 Subsidiary undertakings

The following chart illustrates main companies of the Group structure as of 31 December 2017 [(a)]:



[(a)] LGI is not a subsidiary, it is Non-controlling interest.

Non controlling interest held by LGI:

- Consolidated Statement of Comprehensive Income: Total comprehensive income for the year 2017 include a profit of US$ 13,536,000 (profit of US$ 2,791,000 in 2016 and loss of US$ 7,085,000 in 2015), a loss of US$ 6,200,000 (US$ 10,379,000 in 2016 and US$ 33,260,000 in 2015) and a loss of US$ 945,000 (US$ 3,966,000 in 2016 and US$ 10,190,000 in 2015) corresponding to non-controlling interest held by LGI in GeoPark Colombia Coöperatie U.A., GeoPark Chile S.A. and GeoPark TdF S.A., respectively.

- Consolidated Statement of Financial Position: Total Equity as of 31 December 2017 includes US$ 29,330,000 (US$ 16,168,000 in 2016), US$ 15,953,000 (US$ 22,082,000 in 2016) and a negative amount of US$ 3,368,000 (US$ 2,422,000 in 2016) corresponding to non-controlling interest held by LGI in GeoPark Colombia Coöperatie U.A., GeoPark Chile S.A. and GeoPark TdF S.A., respectively.

- Consolidated Statement of Changes in Equity: Dividends distributed to non-controlling interest of US$ 479,000 in 2017 (US$ 6,406,000 in 2016) correspond to non-controlling interest held by LGI in GeoPark Colombia Coöperatie U.A.

Note

21 Subsidiary undertakings (continued)

Details of the subsidiaries and joint operations of the Group are set out below:

	Name and registered office	Ownership interest
Subsidiaries	GeoPark Argentina Limited (Bermuda)	100%
	GeoPark Argentina Limited – Argentinean Branch	100% (a)
	GeoPark Latin America Limited (Bermuda)	100%
	GeoPark Latin America Limited – Agencia en Chile	100% (a)
	GeoPark S.A. (Chile)	100% (a) (b)
	GeoPark Brazil Exploração y Produção de Petróleo e Gás Ltda. (Brazil)	100% (a)
	GeoPark Chile S.A. (Chile)	80% (a) (c)
	GeoPark Fell S.p.A. (Chile)	80% (a) (c)
	GeoPark Magallanes Limitada (Chile)	80% (a) (c)
	GeoPark TdF S.A. (Chile)	68.8% (a) (d)
	GeoPark Colombia S.A. (Chile)	100% (a) (b)
	GeoPark Colombia SAS (Colombia)	80% (a) (c)
	GeoPark Latin America S.L.U. (Spain)	100% (a)
	GeoPark Colombia Coöperatie U.A. (The Netherlands)	80% (a) (c)
	GeoPark S.A.C. (Peru)	100% (a)
	GeoPark Perú S.A.C. (Peru)	100% (a)
	GeoPark Operadora del Perú S.A.C. (Peru)	100% (a)
	GeoPark Peru S.L.U. (Spain)	100% (a)
	GeoPark Brazil S.L.U. (Spain)	100% (a)
	GeoPark Colombia E&P S.A.(Panama)	100% (a) (b)
	GeoPark Colombia E&P Sucursal Colombia (Colombia)	100% (a) (b)
	GeoPark Mexico S.A.P.I. de C.V. (Mexico)	100% (b)
	Ogarrio E&P S.A.P.I. de C.V. (Mexico)	51% (a) (b)
	GeoPark (UK) Limited (United Kingdom)	100%
Joint operations	Tranquilo Block (Chile)	50% (e)
	Flamenco Block (Chile)	50% (e)
	Campanario Block (Chile)	50% (e)
	Isla Norte Block (Chile)	60% (e)
	Yamu/Carupana Block (Colombia)	89.5%/100% (e)
	Llanos 34 Block (Colombia)	45% (e)
	Llanos 32 Block (Colombia)	12.5%
	CPO-4 Block (Colombia)	50% (e)
	Puelen Block (Argentina)	18%
	Sierra del Nevado Block (Argentina)	18%
	CN-V Block (Argentina)	50% (e)
	Manati Field (Brazil)	10%

(a) Indirectly owned.

(b) Dormant companies.

(c) LG International has 20% interest.

(d) LG International has 20% interest through GeoPark Chile S.A. and a 14% direct interest, totaling 31.2%.

(e) GeoPark is the operator.

Corporate structure reorganization

During 2017, the Company decided to incorporate a subsidiary in the United Kingdom to conduct the businesses in Latin America by adopting all the key resolutions and decisions necessary for such purpose. Also, a tax reform enacted in The Netherlands during September 2017 that would harm the Group´s cashflow, forced the Group to decide the re-domiciliation of its 100% owned Dutch subsidiaries to Spain.

Note

22 Prepaid taxes

Amounts in US$ '000	2017	2016
V.A.T.	27,674	14,052
Income tax payments in advance	1,258	4,517
Other prepaid taxes	939	98
Total prepaid taxes	**29,871**	**18,667**
Classified as follows:		
Current	26,048	15,815
Non current	3,823	2,852
Total prepaid taxes	**29,871**	**18,667**

Note

23 Inventories

Amounts in US$ '000	2017	2016
Crude oil	1,969	1,521
Materials and spares	3,769	1,994
	5,738	**3,515**

Note

24 Trade receivables and Prepayments and other receivables

Amounts in US$ '000	2017	2016
Trade receivables	19,519	18,426
	19,519	**18,426**
To be recovered from co-venturers (Note 33)	2,455	3,311
Related parties receivables (Note 33)	56	42
Prepayments and other receivables	5,242	4,290
	7,753	**7,643**
Total	**27,272**	**26,069**
Classified as follows:		
Current	27,037	25,828
Non current	235	241
Total	**27,272**	**26,069**

Trade receivables that are aged by less than three months are not considered impaired. As of 31 December 2017 and 2016, there are no balances that were aged by more than 3 months, but not impaired. These relate to customers for whom there is no recent history of default. There are no balances overdue between 31 days and 90 days as of 31 December 2017 and 2016.

Note

24 Trade receivables and Prepayments and other receivables (continued)

Movements on the Group provision for impairment are as follows:

Amounts in US$ '000	2017	2016
At 1 January	741	596
Foreign exchange (income) loss	(147)	145
	594	**741**

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

Amounts in US$ '000	Assets as per statement of financial position	
	2017	2016
Loans and receivables		
Trade receivables	19,519	18,426
To be recovered from co-venturers (Note 33)	2,455	3,311
Other financial assets [(a)]	43,488	22,027
Cash and cash equivalents	134,755	73,563
	200,217	**117,327**

[(a)] Non current other financial assets relate to contributions made for environmental obligations according to Colombian and Brazilian government regulations and also include a non current account receivable with the previous owners of one of the Colombian subsidiaries (see Note 28). Current other financial assets corresponds to the security deposit granted in relation to the purchase of Argentinian assets (see Note 35) and short term investments with original maturities up to twelve months and over three months.

Note

25 Financial instruments by category (continued)

	Liabilities as per statement of financial position	
Amounts in US$ '000	**2017**	**2016**
Liabilities at fair value through profit and loss		
Derivative financial instrument liabilities	19,289	3,067
	19,289	**3,067**
Other financial liabilities at amortised cost		
Trade payables	52,557	23,650
Payables to related parties (Note 33)	31,184	27,801
To be paid to co-venturers (Note 33)	10,015	1,614
Borrowings	426,204	358,672
	519,960	**411,737**
Total financial liabilities	**539,249**	**414,804**

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	2017	2016
Trade receivables		
Counterparties with an external credit rating (Moody's)		
B2	70	7,056
Ba3	8,788	-
Baa3	3,614	3,729
Counterparties without an external credit rating		
Group1 [(a)]	7,047	7,641
Total trade receivables	**19,519**	**18,426**

[(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 are denominated in Brazilian Real.

Note

25 Financial instruments by category (continued)

Cash at bank and other financial assets [(a)]

Amounts in US$ '000	2017	2016
Counterparties with an external credit rating (Moody's, S&P, Fitch, BRC Investor Services)		
A1	553	813
A2	298	-
A3	63,853	-
Aaa	15,040	-
Aa3	11,401	42,798
AAA	19,634	14
B2	31	-
Ba1	18	-
Ba2	7	-
Baa1	307	100
Baa2	4,078	4,094
Ba3	2,815	3,497
B3	-	10
BBB	15,064	-
Counterparties without an external credit rating	45,123	44,252
Total	**178,222**	**95,578**

[(a)] The remaining balance sheet item 'cash and cash equivalents' corresponds to cash on hand amounting to US$ 21,000 (US$ 12,000 in 2016).

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
At 31 December 2017				
Borrowings	27,625	27,625	82,875	480,250
Trade payables	52,557	-	-	-
Payables to related parties	7,331	2,068	27,087	-
	87,513	**29,693**	**109,962**	**480,250**
At 31 December 2016				
Borrowings	48,958	43,304	355,064	-
Trade payables	23,650	-	-	-
Payables to related parties	1,561	1,561	22,018	-
	74,169	**44,865**	**377,082**	**-**

Note

25 Financial instruments by category (continued)

Fair value measurement of financial instruments

Accounting policies for financial instruments have been applied to classify as either: loans and receivables, held-to-maturity, available-for-sale, or fair value through profit and loss. 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).

This note provides an update on the judgements and estimates made by the Group in determining the fair values of the financial instruments since the last annual financial report.

(a) Fair value hierarchy

The following table presents the Group's financial assets and financial liabilities measured and recognised at fair value at 31 December 2017 and 2016 on a recurring basis:

Amounts in US$ '000	Level 2	At 31 December 2017
Liabilities		
Derivative financial instrument liabilities		
Commodity risk management contracts	19,289	19,289
Total Liabilities	**19,289**	**19,289**

Amounts in US$ '000	Level 2	At 31 December 2016
Liabilities		
Derivative financial instrument liabilities		
Commodity risk management contracts	3,067	3,067
Total Liabilities	**3,067**	**3,067**

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 at 31 December 2017.

Note

25 Financial instruments by category (continued)

Fair value measurement of financial instruments (continued)

(b) 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 market-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 counter-party 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.

(c) Fair values of other financial instruments (unrecognised)

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 at 31 December 2017 amounts to US$ 425,118,000 (US$ 346,180,000 in 2016). The fair values are based on cash flows discounted using a rate based on the borrowing rate of 6.90% (7.60% in 2016) and are within level 2 of the fair value hierarchy.

Note

26 Share capital

Issued share capital	2017	2016
Common stock (amounts in US$ '000)	**61**	**60**
The share capital is distributed as follows:		
Common shares, of nominal US$ 0.001	60,596,219	59,940,881
Total common shares in issue	**60,596,219**	**59,940,881**

Authorised 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:

Common shares

As of 31 December 2017, 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	Date	Shares issued (millions)	Shares closing (millions)	US$(`000) Closing
Shares outstanding at the end of 2015			**59.5**	**59**
Stock awards	Feb 2016	0.4	59.9	60
Stock awards	Dec 2016	0.5	60.4	60
Stock awards	Dec 2016	0.1	60.5	60
Buyback program	Dec 2016	(0.6)	59.9	60
Shares outstanding at the end of 2016			**59.9**	**60**
Stock awards	Jan 2017	0.1	60.0	60
Stock awards	Dec 2017	0.1	60.1	60
Stock awards	Dec 2017	0.5	60.6	61
Shares outstanding at the end of 2017			**60.6**	**61**

Note

26 Share capital (continued)

Stock Award Program and Other Share Based Payments

On 14 December 2017, 490,000 common shares were allotted to the trustee of the Employee Beneficiary Trust ("EBT"), generating a share premium of US$ 2,513,000.

On 15 December 2016, 379,500 common shares were allotted to the trustee of the Employee Beneficiary Trust ("EBT"), generating a share premium of US$ 3,940,000.

On 12 November 2015 and 22 December 2015, 817,600 and 478,000 common shares were allotted to the trustee of the Employee Beneficiary Trust ("EBT"), generating a share premium of US$ 11,359,000 and US$ 3,577,000, respectively.

In January 2017, 82,306 shares were issued to key management as bonus compensation, generating a share premium of US$ 332,000.

On 8 February 2016, 468,405 shares were issued to Executive Directors and key management as bonus compensation, generating a share premium of US$ 1,512,000.

On 13 September 2017, 12,546 shares were issued pursuant to a consulting agreement for services rendered to GeoPark Limited generating a share premium of US$ 43,000.

On 6 September 2016, 8,333 shares were issued pursuant to a consulting agreement for services rendered to GeoPark Limited generating a share premium of US$ 38,000.

On 30 November 2015, 720,000 new common shares were issued to the Executive Directors, generating a share premium of US$ 7,309,000.

During 2017, the Company issued 70,485 (137,897 in 2016 and 99,555 in 2015) shares to Non-Executive Directors in accordance with contracts as compensation, generating a share premium of US$ 257,000 (US$ 541,848 in 2016 and US$ 486,692 in 2015). The amount of shares issued is determined considering the contractual compensation and the fair value of the shares for each relevant period.

Buyback Program

On 19 December 2014, the Company approved a program to repurchase up to US$ 10,000,000 of common shares, par value US$ 0.001 per share of the Company (the "Repurchase Program"). The Repurchase Program began on 19 December 2014 and was resumed on 14 April 2015 and then on 10 June 2015, expiring on 18 August 2015. During 2016, the Repurchase Program began on 6 April 2016 and then was resumed during the year until November 2016. The Shares repurchased will be used to offset, in part, any expected dilution effects resulting from the Group's employee incentive schemes, including grants under the Company's Stock Award Plan and the Limited Non-Executive Director Plan. In 2017, no shares were repurchased. During 2016 and 2015, the Company purchased 588,868 and 370,074 73,082 common shares for a total amount of US$ 1,991,000 and US$ 1,615,000, respectively. These transactions had no impact on the Group's results.

Note

27 Borrowings

Amounts in US$ '000	2017	2016
Outstanding amounts as of 31 December		
2024 Notes (a)	426,124	-
Notes GeoPark Latin America Agencia en Chile (b)	-	304,059
Banco Itaú (c)	-	49,763
Banco de Chile (d)	-	4,709
Banco de Crédito e Inversiones (e)	80	141
	426,204	**358,672**
Classified as follows:		
Current	7,664	39,283
Non current	418,540	319,389

(a) During September 2017, the Company successfully placed US$ 425,000,000 notes which were offered to qualified institutional buyers in accordance with Rule 144A under the United States Securities Act, and outside the United States to non-U.S. persons in accordance with Regulation S under the United States Securities Act.

The Notes carry a coupon of 6.50% per annum. Final maturity of the notes will be 21 September 2024. The Notes are secured with a pledge of all of the equity interests of the Company, directly or indirectly, in GeoPark Colombia Coöperatie U.A. and GeoPark Chile S.A.. The debt issuance cost for this transaction amounted to US$ 6,683,000 (debt issuance effective rate: 6.90%). The indenture governing the Notes due 2024 includes incurrence test covenants that provides among other things, that, during the first two years from the issuance date, the Net Debt to Adjusted EBITDA ratio should not exceed 3.5 times and the Adjusted EBITDA to Interest ratio should exceed 2 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 indenture 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, (other than in each case, certain specific exceptions). As of the date of these Consolidated Financial Statements, the Company is in compliance of all the indenture's provisions and covenants.

The net proceeds from the Notes were used by the Company (i) to make a capital contribution to its wholly-owned subsidiary, GeoPark Latin America Limited Agencia en Chile ("GeoPark LA Agencia"), providing it with sufficient funds to fully repay the 7.50% senior secured notes due 2020 and to pay any related fees and expenses, including call premium, and (ii) for general corporate purposes, including capital expenditures and to repay existing indebtedness.

Note

27 Borrowings (continued)

(b) During February 2013, the Group successfully placed US$ 300,000,000 notes which were offered under Rule 144A and Regulation S exemptions of the United States Securities laws. The Notes carried a coupon of 7.50% per annum and mature on 11 February 2020. These Notes were fully repaid in September 2017.

(c) During March 2014, GeoPark executed a loan agreement with Itaú BBA International for US$ 70,450,000 to finance the acquisition of a 10% working interest in the Manatí field in Brazil. The loan was fully repaid in September 2017.

(d) During December 2015, GeoPark executed a loan agreement with Banco de Chile for US$ 7,028,000 to finance the start-up of new Ache gas field in GeoPark-operated Fell Block. The interest rate applicable to this loan is LIBOR plus 2.35% per annum. The interest and the principal have been paid on monthly basis; with a six months grace period, with final maturity on December 2017. As of the date of these Consolidated Financial Statements, the loan was fully repaid.

(e) During February 2016, GeoPark executed a loan agreement with Banco de Crédito e Inversiones for US$ 186,000 to finance the acquisition of vehicles for the Chilean operation. The interest rate applicable to this loan is 4.14% per annum. The interest and the principal will be paid on monthly basis, with final maturity on February 2019.

As of the date of these Consolidated Financial Statements, the Group has available credit lines for over US$ 33,000,000.

Note

28 Provisions and other long-term liabilities

Amounts in US$ '000	Asset retirement obligation	Deferred Income	Other	Total
At 1 January 2016	**31,617**	**5,033**	**5,800**	**42,450**
Addition to provision	1,195	1,375	2,686	5,256
Recovery of abandonments costs	(5,504)	-	-	(5,504)
Exchange difference	(1,614)	-	538	(1,076)
Foreign currency translation	1,614	-	-	1,614
Amortisation	-	(2,924)	-	(2,924)
Unwinding of discount	2,554	-	139	2,693
At 31 December 2016	**29,862**	**3,484**	**9,163**	**42,509**
Addition to provision	5,943	-	2,220	8,163
Exchange difference	134	-	1,154	1,288
Foreign currency translation	(134)	-	-	(134)
Amortisation	-	(657)	-	(657)
Unwinding of discount	2,607	-	172	2,779
Unused amounts reversed	-	-	(2,535)	(2,535)
Amounts used during the year	(337)	(1,375)	(3,417)	(5,129)
At 31 December 2017	**38,075**	**1,452**	**6,757**	**46,284**

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 contributions received to improve the project economics of the gas wells in Chile. The amortisation is in line with the related asset. The addition in 2016 and the amounts used in 2017 correspond to the deferred income related to the take or pay provision associated to gas sales in Brazil.

As of 31 December 2016, Other included a provision for an amount of US$ 5,636,000 related to fiscal controversies associated to income taxes in one of the Colombian subsidiaries. These controversies related to fiscal periods prior to the acquisition of these subsidiaries by the Group. During 2017, GeoPark settled the controversies by paying a total amount of US$ 3,389,000 to the tax authority, under a valid tax amnesty. In connection to this, the Group recorded an account receivable with the previous owners for the amount paid under the tax amnesty, considering the contractual right of recovering amounts paid related to fiscal years prior to the acquisition. This account receivable is recognised under other financial assets in the balance sheet. In addition, actions taken by the Group to maximize ongoing work projects and to reduce expenses, including renegotiations and reduction of oil and gas service contracts and other initiatives included in the cost cutting program adopted may expose the Group to claims and contingencies from interested parties that may have a negative impact on its business, financial condition, results of operations and cash flows. So, the additions in 2016 reflects the future contingent payments in connection with claims of third parties.

Note

29 Trade and other payables

Amounts in US$ '000	2017	2016
V.A.T	1,118	1,102
Trade payables	52,557	23,650
Payables to related parties [a] (Note 33)	31,184	27,801
Customer advance payments (Note 3)	10,000	20,000
Staff costs to be paid	9,143	7,749
Royalties to be paid	4,110	1,503
Taxes and other debts to be paid	4,191	3,355
To be paid to co-venturers (Note 33)	10,015	1,614
	122,318	**86,774**
Classified as follows:		
Current	96,397	52,008
Non current	25,921	34,766

[a]The outstanding amount corresponds to advanced cash call payments granted by LGI to GeoPark Chile S.A. for financing Chilean operations in TdF's blocks. The expected maturity of these balances is July 2020 and the applicable interest rate is 8% per annum.

The average credit period (expressed as creditor days) during the year ended 31 December 2017 was 95 days (2016: 83 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

30 Share-based payment

IPO Award Program and Executive Stock Option plan

The Group has established different stock awards programs and other share-based payment plans to incentivise the Directors, senior management and employees, enabling them to benefit from the increased market capitalisation of the Company.

Stock Award Program and Other Share Based Payments

During 2008, GeoPark Shareholders voted to authorize the Board to use up to 12% of the issued share capital of the Company at the relevant time for the purposes of the Performance-based Employee Long-Term Incentive Plan.

Note

30 Share-based payment (continued)

During 2016, the Group approved a share-based compensation program for 1,619,105 shares. Main characteristics of the Stock Awards Programs are:

- All employees are eligible.
- Exercise price is equal to the nominal value of shares.
- Vesting period is three years.
- Each employee could receive up to three salaries by achieving the following conditions: continue to be an employee, the stock market price at the date of vesting should be above US$ 3 and obtain the Group minimum production, adjusted EBITDA and reserves target for the year of vesting.

Also during 2016, the Group approved a plan named Value Creation Plan ("VCP") oriented to Top Management. Main characteristics of the VCP are:

- Awards payables in a variable number of shares which shall not exceed the quantity of 2,976,781 shares.
- Subject to certain market conditions, among others, reaching a stock market price for the Company shares of US$ 4.05 at vesting date.
- Vesting date: 31 December 2018.

VCP has been classified as an equity-settled 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 and explanations:

						Charged to net loss / profit		
Year of issuance	Awards at the beginning	Awards granted in the year	Awards forfeited	Awards exercised	Awards at year end	2017	2016	2015
2016	1,619,105	-	31,109	-	1,587,996	865	445	-
2014	490,000	-	-	490,000	-	838	821	898
2013	-	-	-	-	-	-	-	594
2012	-	-	-	-	-	-	855	636
2011	-	-	-	-	-	-	-	879
Subtotal						**1,703**	**2,121**	**3,007**
Stock options to Executive Directors	-	-	-	-	-	-	-	2,390
Shares granted to Non-Executive Directors	-	70,485		70,485		454	400	371
VCP 2013	-	-	-	-	-	-	-	617
VCP 2016	-	-	-	-	-	1,868	934	-
Executive Directors Bonus	-	-	-	-	-	-	(325)	400
Key Management Bonus	82,306	-	-	82,306	-	-	202	1,438
Stock awards for service contracts	-	12,546	-	12,546	-	50	35	-
	2,191,411	**83,031**	**31,109**	**655,337**	**1,587,996**	**4,075**	**3,367**	**8,223**

The awards that are forfeited correspond to employees that had left the Group before vesting date.

Note

31 Interests in Joint operations

The Group has interests in joint operations, which are engaged in the exploration of hydrocarbons in Chile, Colombia, Brazil and Argentina.

In Chile, GeoPark is the operator in all the blocks. In Colombia, GeoPark is the operator in Llanos 34 and Yamu/Carupana blocks. In Argentina, GeoPark is the operator in CN-V block.

The following amounts represent the Group's share in the assets, liabilities and results of the joint operations which have been recognised in the Consolidated Statement of Financial Position and Statement of Income:

Subsidiary / Joint operation	Interest	PP&E E&E Assets	Other Assets	Total Assets	Total Liabilities	NET ASSETS/ (LIABILITIES)	Revenue	Operating (loss) profit
2017								
GeoPark Magallanes Ltda.								
Tranquilo Block	50%	-	55	55	(432)	(377)	-	(48)
GeoPark TdF S.A.								
Flamenco Block	50%	9,893	-	9,893	(1,223)	8,670	879	(1,422)
Campanario Block	50%	17,347	-	17,347	(233)	17,114	-	(150)
Isla Norte Block	60%	9,553	-	9,553	(60)	9,493	-	(161)
Colombia SAS								
Yamu/Carupana Block	89.5%	4,741	1	4,742	(2,993)	1,749	3,072	(2,721)
Llanos 34 Block	45%	131,193	4,563	135,756	(5,847)	129,909	259,815	163,917
Llanos 32 Block	12.5%	835	209	1,044	(492)	552	1,784	(319)
GeoPark Brazil Exploração y Produção de Petróleo e Gas Ltda.								
Manati Field	10%	44,167	19,126	63,293	(11,444)	51,849	34,238	12,731
POT-T-747	70%	849	358	1,207	(1,091)	116	-	-
GeoPark Argentina Limited – Argentinean Branch								
CN-V Block	50%	6,819	347	7,166	(984)	6,182	70	(1,163)
Puelen Block	18%	1,318	72	1,390	(232)	1,158	-	(546)
Sierra del Nevado Block	18%	568	169	737	(837)	(100)	-	(474)

Note

31 Interests in Joint operations (continued)

Subsidiary / Joint operation	Interest	PP&E E&E Assets	Other Assets	Total Assets	Total Liabilities	NET ASSETS/ (LIABILITIES)	Revenue	Operating (loss) profit
2016								
GeoPark Magallanes Ltda.								
Tranquilo Block	50%	-	55	55	(424)	(369)	-	(40)
GeoPark TdF S.A.								
Flamenco Block	50%	15,108	-	15,108	(93)	15,015	1,004	(1,988)
Campanario Block	50%	29,718	-	29,718	(1)	29,717	-	(399)
Isla Norte Block	60%	9,920	-	9,920	(1)	9,919	5	(438)
Colombia SAS								
Yamu/Carupana Block	89,5%	3,418	-	3,418	(2,289)	1,129	18	(307)
Llanos 34 Block	45%	79,811	693	80,504	(3,943)	76,561	125,400	83,193
Llanos 32 Block	10%	3,819	-	3,819	(211)	3,608	2,303	1,043
GeoPark Brazil Exploração y Produção de Petróleo e Gas Ltda.								
Manati Field	10%	54,166	15,791	69,957	(8,442)	61,515	29,719	20,945
2015								
GeoPark Magallanes Ltda.								
Tranquilo Block	50%	-	45	45	(2)	43	-	(69)
GeoPark TdF S.A.								
Flamenco Block	50%	14,932	-	14,932	(53)	14,879	1,810	(51,411)
Campanario Block	50%	27,570	-	27,570	(10)	27,560	13	(7,267)
Isla Norte Block	60%	8,583	-	8,583	(16)	8,567	355	(5,661)
Colombia SAS								
Llanos 17 Block	36.84%	-	-	-	(93)	(93)	3	(6,325)
Yamu/Carupana Block	89,5%	3,569	2,061	5,630	(2,235)	3,395	1,409	(16,552)
Llanos 34 Block	45%	76,667	429	77,096	(3,295)	73,801	114,276	53,049
Llanos 32 Block	10%	3,106	96	3,202	(213)	2,989	8,258	(1,343)
GeoPark Brazil Exploração y Produção de Petróleo e Gas Ltda.								
Manati Field	10%	50,801	12,930	63,731	(10,395)	53,336	32,388	20,354

Capital commitments are disclosed in Note 32 (b).

Note

32 Commitments

(a) Royalty commitments

In Colombia, royalties on production are payable to the Colombian Government and are determined on a field-by-field basis using a level of production sliding scale at a rate which ranges between 6%-8%. The Colombian National Hydrocarbons Agency ("ANH") also has an additional economic right equivalent to 1% of production, net of royalties.

Under Law 756 of 2002, as modified by Law 1530 of 2012, the royalties on Colombian production of light and medium oil are calculated on a field-by-field basis, using the following sliding scale:

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%

When the API is lower than 15°, the payment is reduced to the 75% of the total calculation.

In accordance with Llanos 34 Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5,000,000 of barrels and the WTI exceeds the base price settled in table A, the Group should deliver to ANH a share of the production net of royalties in accordance with the following formula: Q = ((P – Po) / P) x S; where Q = Economic right to be delivered to ANH, P = WTI, Po = Base price (see table A) and S = Share (see table B).

Table A

°API	Po (US$/barrel)	WTI (P)
>29°	30.22	Po < P < 2Po
>22°<29°	31.39	2Po < P < 3Po
>15°<22°	32.56	3Po < P < 4Po
>10°<15°	46.50	4Po < P < 5Po
		5Po < P

Table B

S
30%
35%
40%
45%
50%

Note

32 Commitments (continued)

(a) Royalty commitments (continued)

Additionally, under the terms of the Winchester Stock Purchase Agreement, GeoPark is obligated to make certain payments to the previous owners of Winchester based on the production and sale of hydrocarbons discovered by exploration wells drilled after 25 October 2011. These payments involve an overriding royalty equal to an estimated 4% carried interest on the part of the vendor. As at the balance sheet date and based on preliminary internal estimates of additions of 2P reserves since acquisition, the Group's best estimate of the total commitment over the remaining life of the concession is in a range between US$ 80,000,000 and US$ 90,000,000. During 2017, the Group has accrued and paid US$ 11,369,000 (US$ 5,414,000 in 2016 and US$ 7,100,000 in 2015) and US$ 9,981,000 (US$ 3,772,000 in 2016 and US$ 9,200,000 in 2015), respectively.

In Chile, royalties are payable to the Chilean Government. In the Fell Block, royalties are calculated at 5% of crude oil production and 3% of gas production. In the Flamenco Block, Campanario Block and Isla Norte Block, royalties are calculated at 5% of gas and oil production.

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 Manatí Block, royalties are calculated at 7.5% of gas production.

In Argentina, crude oil production accrues royalties payable to the Province of Mendoza equivalent to 12% on estimated value at well head of those products. This value is equivalent to final sales price less transport, storage and treatment costs.

(b) Capital commitments

Colombia

The VIM 3 Block minimum investment program consists of 200 sq km of 2D seismic and drilling one exploratory well, with a total estimated investment of US$ 22,290,800 during the initial three year exploratory period ending 2 September 2018.

Note

32 Commitments (continued)

(b) Capital commitments (continued)

Colombia (continued)

The Llanos 34 Block (45% working interest) has committed to drill two exploratory wells, one before 15 March 2017 and the other before 14 September 2019. The remaining commitment amounted to US$ 6,255,000 at GeoPark's working interest. As of the date of these Consolidated Financial Statements, GeoPark is awaiting the ANH's approval of the wells already drilled that were presented as fulfilment of the commitments to be performed in the block. After this approval, the remaining commitment would amount to US$ 3,008,000.

The Llanos 32 Block (12% working interest) has committed to drill one exploratory well before 20 August 2018. The remaining commitment amounts to US$ 587,500 at GeoPark's working interest.

Argentina

On 20 August 2014, the consortium of GeoPark and Pluspetrol 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 Energia S.A. ("EMESA"). The consortium consists of Pluspetrol (Operator with a 72% working interest ("WI"), EMESA (Non-operated with a 10% WI) and GeoPark (Non-operated with an 18% WI). As of the date of these Consolidated Financial Statements, the remaining commitments in the blocks for the first exploratory period amount to US$ 1,200,000 at GeoPark's working interest.

On 22 July 2015, GeoPark signed a farm-in agreement with Wintershall for the CN-V Block in Argentina. GeoPark will operate during the exploratory phase and receive a 50% working interest in the CN-V Block in exchange for its commitment to drill two exploratory wells, for a total of US$ 10,000,000. As of the date of these Consolidated Financial Statements, GeoPark has already drilled and completed one of the two committed exploratory wells for a total amount of US$ 5,455,000.

Chile

The remaining investment commitment for the second exploratory phase in the Flamenco Block relates to the drilling of one exploratory well to be assumed 100% by GeoPark and amounts to US$ 2,100,000. On 30 June 2017, the Chilean Ministry accepted GeoPark's proposal to extend the second exploratory phase for an additional period of 18 months, ending on 7 May 2019.

Note

32 Commitments (continued)

(b) Capital commitments (continued)

Chile (continued)

The investment commitment for the first exploratory period in the Campanario and Isla Norte Blocks has already been fulfilled. The investments to be made in the second exploratory period will be assumed 100% by GeoPark. On 29 May 2017, the Chilean Ministry accepted GeoPark's proposal to update the value of the commitments in both the Campanario and Isla Norte Blocks as well as the guarantees related to those commitments. Consequently, the future investment commitments assumed by GeoPark for the second exploratory period are up to:

- Campanario Block: 3 exploratory wells before 10 July 2019 (US$ 4,758,000)
- Isla Norte Block: 2 exploratory wells before 7 May 2019 (US$ 2,855,000)

As of 31 December 2017, the Group has established guarantees for its total commitments.

Brazil

The future investment commitments assumed by GeoPark are up to:

- SEAL-T-268 Block: before 15 May 2017 (US$ 230,000). On 12 May 2017, the Brazilian National Agency of Petroleum, Natural Gas and Biofuels ("ANP") notified the suspension of the exploratory period to fulfill the commitments in the block.
- REC-T-94 Block: 2 exploratory wells before 12 July 2017 (US$ 2,300,000). An exploratory well was drilled and completed in April 2017. On 12 July 2017, the ANP notified the suspension of the exploratory period to fulfill the commitments in the block.
- REC-T-93 Block: 3D seismic before 20 December 2018 (US$ 50,000).
- REC-T-128 Block: 1 exploratory well before 20 December 2018 (US$ 2,690,000).
- POT-T-747 Block: 1 exploratory well before 20 December 2018 (US$ 1,840,000). An exploratory well was drilled in December 2017.
- POT-T-882 Block: 35 sq km of 2D seismic before 20 December 2018 (US$ 480,000).
- POT-T-619 Block: 1 well before 16 September 2018 (US$ 700,000).

(c) Operating lease commitments – Group company as lessee

The Group leases various plant and machinery under non-cancellable operating lease agreements.

The Group also leases offices under non-cancellable operating lease agreements. The lease terms are between 2 and 3 years, and most of lease agreements are renewable at the end of the lease period at market rate.

Note

32 Commitments (continued)

(c) Operating lease commitments – Group company as lessee (continued)

During 2017 a total amount of US$ 46,195,000 (US$ 47,871,000 in 2016 and US$ 16,731,000 in 2015) was charged to the income statement and US$ 34,160,000 of operating leases were capitalised as Property, plant and equipment related to rental of drilling equipment and machinery (US$ 32,058,000 in 2016 and US$ 7,102,000 in 2015).

The future aggregate minimum lease payments under non-cancellable operating leases are as follows:

Amounts in US$ '000	2017	2016	2015
Operating lease commitments			
Falling due within 1 year	32,180	67,752	12,878
Falling due within 1 – 3 years	5,777	14,031	8,257
Falling due within 3 – 5 years	2,793	5,066	2,456
Falling due over 5 years	-	114	309
Total minimum lease payments	**40,750**	**86,963**	**23,900**

Note

33 Related parties

Controlling interest

The main shareholders of GeoPark Limited, a company registered in Bermuda, as of 31 December 2017, are:

Shareholder	Common shares	Percentage of outstanding common shares
James F. Park [a]	7,891,269	13.02%
Gerald E. O'Shaughnessy[b]	7,193,316	11.87%
Manchester Financial Group, LP	5,103,439	8.42%
IFC Equity Investments[c]	3,422,476	5.65%
Juan Cristóbal Pavez[d]	2,961,520	4.89%
Other shareholders	34,024,199	56.15%
	60,596,219	**100.00%**

[a] Held by Energy Holdings, LLC, which is controlled by James F. Park, a member of our Board of Directors.
[b] Beneficially owned by Mr. O'Shaughnessy directly and indirectly through GP Investments LLP, GPK Holdings, and other investment vehicles.
[c] IFC Equity Investments voting decisions are made through a portfolio management process which involves consultation from investment officers, credit officers, managers and legal staff.
[d] Held through Socoservin Overseas Ltd, which is controlled by Juan Cristóbal Pavez. The common shares reflected as being held by Mr. Pavez include 83,716 common shares held by him personally.

Note

33 Related parties (continued)

Balances outstanding and transactions with related parties

Account (Amounts in ´000)	Transaction in the year	Balances at year end	Related Party	Relationship
2017				
To be recovered from co-venturers	-	2,455	Joint Operations	Joint Operations
Prepayments and other receivables	-	56	LGI	Partner
Payables account	-	(31,184)	LGI	Partner
To be paid to co-venturers	-	(10,015)	Joint Operations	Joint Operations
Financial results	2,224	-	LGI	Partner
Geological and geophysical expenses	170	-	Carlos Gulisano	Non-Executive Director [a]
Administrative expenses	411	-	Pedro Aylwin	Executive Director [b]
2016				
To be recovered from co-venturers	-	3,311	Joint Operations	Joint Operations
Prepayments and other receivables	-	42	LGI	Partner
Payables account	-	(27,801)	LGI	Partner
To be paid to co-venturers	-	(1,614)	Joint Operations	Joint Operations
Financial results	1,587	-	LGI	Partner
Geological and geophysical expenses	113	-	Carlos Gulisano	Non-Executive Director [a]
Administrative expenses	371	-	Pedro Aylwin	Executive Director [b]
2015				
To be recovered from co-venturers	-	4,634	Joint Operations	Joint Operations
Prepayments and other receivables	-	38	LGI	Partner
Payables account	-	(21,045)	LGI	Partner
To be paid to co-venturers	-	(113)	Joint Operations	Joint Operations
Financial results	1,560	-	LGI	Partner
Geological and geophysical expenses	101	-	Carlos Gulisano	Non-Executive Director [a]
Administrative expenses	66	-	Carlos Gulisano	Non-Executive Director [a]
Administrative expenses	377	-	Pedro Aylwin	Executive Director [b]

[a] Corresponding to consultancy services.

[b] Corresponding to wages and salaries for US$ 271,000 (US$ 246,000 in 2016 and US$ 317,000 in 2015) and bonus for US$ 140,000 (US$ 125,000 in 2016 and US$ 60,000 in 2015).

Note

33 Related parties (continued)

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

34 Fees paid to Auditors

Amounts in US$ '000	2017	2016	2015
Audit fees	726	487	557
Audit related fees	137	-	-
Tax services fees	212	134	129
Non-audit services fees	39	-	-
Fees paid to auditors	**1,114**	**621**	**686**

Non-audit services fees relate to consultancy and other services for 2017.

Note

35 Business transactions

a. Peru

Entry in Peru

The Group has executed a Joint Investment Agreement and Joint Operating Agreement with Petróleos del Peru S.A. ("Petroperu") to acquire an interest in and operate the Morona Block located in northern Peru. GeoPark will assume a 75% working interest ("WI") of the Morona Block, with Petroperu retaining a 25% WI. The transaction has been approved by the Board of Directors of both Petroperu and GeoPark. The agreement was subject to Peru regulatory approval, which was completed on 1 December 2016 following the issuance of Supreme Decree 031-2016-MEM.

The Morona Block, also known as Lote 64, covers an area of 1.9 million acres on the western side of the Marañón Basin, one of the most prolific hydrocarbon basins in Peru. It contains the Situche Central oil field, which has been delineated by two wells (with short term tests of approximately 2,400 and 5,200 bopd of 35-36° API oil each) and by 3D seismic.

In accordance with the terms of the agreement, GeoPark has committed to carry Petroperu on a work program that provides for testing and start-up production of one of the existing wells in the field, subject to certain technical and economic conditions being met. During 2017, GeoPark recognised an initial consideration owed to Petroperu that could be up to US$ 10,684,000, subject to GeoPark's review and approval of supporting documentation. This amount will be offset by the Petroperu's interest in the operation expenses to be incurred by GeoPark in the block. Expected capital expenditures in 2018 for the Morona Block are mainly related to facility maintenance and environmental and engineering studies.

Note

35 Business transactions (continued)

b. Colombia

Swap operation

On 19 November 2015, the Colombian subsidiary agreed to exchange its 10% non-operating economic interest in Cerrito Block for additional interests held by Trayectoria, the counterpart in the Yamú Block, operated by GeoPark, that includes a 10% economic interest in all of the Yamú fields. According to the terms of the swap operation, GeoPark had written off a receivable with Trayectoria.

Following this transaction, GeoPark continued to be the operator and have an 89.5% interest in the Carupana Field and 100% in Yamú and Potrillo Fields. The Group recognised, during 2015, a loss of US$ 296,000 generated by this transaction.

Acquisition of Tiple Block

GeoPark executed a joint operation agreement related to certain exploration activities in a new high-potential exploration acreage (“Tiple Block Acreage”) in the Llanos Basin in Colombia, through a partnership with CEPSA Colombia S.A. (a subsidiary of CEPSA SAU, the Spanish integrated energy and petrochemical company).

The Tiple Block Acreage is located adjacent to GeoPark’s Llanos 34 Block (GeoPark operated, 45% WI). This exploration area covers approximately 21,000 acres and has full 3D seismic coverage.

The agreement provides for GeoPark to drill one exploration well, which is scheduled to be drilled in the first half of 2018. The total estimated investment amounts to between US$ 7,000,000 and US$ 8,000,000 (including drilling, completion, civil works and other facilities).

Incremental interest in Llanos 32 Block

On 22 August 2017, GeoPark acquired an additional 2.5% interest in the Llanos 32 Block. No gain or loss has been generated by this transaction.

Zamuro Farm-in agreement

GeoPark executed a farm-in agreement to drill the Zamuro exploration prospect, which is located in the Llanos 32 block (GeoPark non-operated, 12.5% WI). The farm-in agreement provides for the drilling of an exploration well to be funded by GeoPark and, in the event of a commercial discovery, GeoPark would increase its economic interest to 56.25% in the Zamuro field area. The well is scheduled to be drilled in the second half of 2018.

Note

35 Business transactions (continued)

c. Argentina

Acquisition of the Aguada Baguales, El Porvenir and Puesto Touquet blocks

On 18 December 2017, GeoPark executed an asset purchase agreement to acquire a 100% working interest and operatorship of the Aguada Baguales, El Porvenir and Puesto Touquet blocks, which are located in the Neuquen Basin, for a total consideration of US$ 52,000,000. Closing of the transaction is subject to customary regulatory approvals, and is expected in the first quarter 2018.

As of the date of these Consolidated Financial Statements, GeoPark has recorded the security deposit of US$ 15,600,000 granted to the seller within “Other financial assets” in the Consolidated Statement of Financial Position. No other amounts are recorded in relation with this transaction until its closing.

Note

36 Impairment test on Property, plant and equipment

Oil price crisis started in the second half of 2014 and prices fell dramatically, WTI and Brent, the main international oil price markers, fell more than 60% between October 2014 and February 2016. Because of those market conditions, during 2015, the Group undertook a decisive cost cutting program to ensure its ability to both maximize the work program and preserve its liquidity. The main decisions included:

- Reduction of its capital investment taking advantage of the discretionary work program.
- Deferment of capital projects by regulatory authority and partner agreement.
- Renegotiation and reduction of oil and gas service contracts, including drilling and civil work contractors, as well as transportation trucking and pipeline costs.
- Operating cost improved efficiencies and temporary suspension of certain marginal producing oil and gas fields.

During February 2015, the Group reduced its workforce significantly. This reduction streamlined certain internal functions and departments for creating a more efficient workforce in the current economic environment. As a result, the Group achieved cost savings associated with the reduction of full-time and temporary employees, excluding one-time termination costs. Continuous efforts and actions to reduce costs and preserve liquidity have continued since.

As a result of the situation described, the Group recognised an impairment loss of US$ 149,574,000 in 2015 after evaluating the recoverability of its fixed assets affected by oil price drop, as such situation constitutes an impairment indicator according to IAS 36 and, consequently, it triggers the need of assessing fair value of the assets involved against their carrying amount.

The Management of the Group considers as Cash Generating Unit (CGU) each of the blocks in which the Group has working or economic interests. The blocks with no material investment on fixed assets or with operations that are not linked to oil prices were not subject to impairment test.

Note

36 Impairment test on Property, plant and equipment (continued)

During 2016 and 2017 the impairment tests were reviewed. The main assumptions taken into account for the impairment tests for the blocks below mentioned were:

- The future oil prices have been calculated taking into consideration the oil curves prices available in the market, provided by international advisory companies, weighted through internal estimations in accordance with price curves used by D&M;
- Three price scenarios were projected and weighted in order to minimize misleading: 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 marker 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 (see below table "Oil price scenarios");
- The levels of production have been linked to certified risked 1P, 2P and 3P reserves (see Note 4);
- Production and structure costs were estimated considering internal historical data according to GeoPark's own records and aligned to 2018 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 and Production facilities and machinery;
- 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
2018	64.9	64.9	64.9	64.9
2019	53.2	62.5	71.7	63.4
2020	54.4	63.9	73.4	64.9
Over 2021	54.3	63.7	73.2	64.7

[(a)] The percentages indicated between brackets represent the Group estimation regarding each price scenario.

As a consequence of the evaluation no additional impairment loss was recognised in 2017. In 2016, part of the impairment recorded in Colombia was reversed for an amount of US$ 5,664,000 due to increase in estimated market prices and improvements in cost structure.

Note

37 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 31 December 2008. This information includes the Group's oil and gas production activities carried out in Chile, Colombia, Brazil, Argentina and Peru.

Table 1 - Costs incurred in exploration, property acquisitions and development [(a)]

The following table presents those costs capitalised as well as expensed that were incurred during each of the years ended as of 31 December 2017, 2016 and 2015. 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	Chile	Colombia	Argentina	Brazil	Peru	Total
Year ended 31 December 2017						
Acquisition of properties						
Proved	-	-	-	-	-	-
Unproved	-	-	-	-	-	-
Total property acquisition	-	-	-	-	-	-
Exploration	3,283	37,017	8,080	5,207	743	54,330
Development	10,231	49,268	167	1,210	14,074	74,950
Total costs incurred	**13,514**	**86,285**	**8,247**	**6,417**	**14,817**	**129,280**
Amounts in US$ '000	**Chile**	**Colombia**	**Argentina**	**Brazil**	**Peru**	**Total**
Year ended 31 December 2016						
Acquisition of properties						
Proved	-	-	-	-	-	-
Unproved	-	-	-	-	-	-
Total property acquisition						
Exploration	5,519	15,233	1,894	2,555	-	25,201
Development	4,566	12,500	-	191	-	17,257
Total costs incurred	**10,085**	**27,733**	**1,894**	**2,746**	-	**42,458**
Amounts in US$ '000	**Chile**	**Colombia**	**Argentina**	**Brazil**	**Peru**	**Total**
Year ended 31 December 2015						
Acquisition of properties						
Proved	-	-	-	-	-	-
Unproved	-	-	-	-	-	-
Total property acquisition						
Exploration	3,598	14,845	1,103	2,562	-	22,108
Development	13,315	14,752	56	3,780	-	31,903
Total costs incurred	**16,913**	**29,597**	**1,159**	**6,342**	-	**54,011**

[(a)] Includes capitalised amounts related to asset retirement obligations.

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

Table 2 - Capitalised costs related to oil and gas producing activities

The following table presents the capitalised costs as at 31 December 2017, 2016 and 2015, for proved and unproved oil and gas properties, and the related accumulated depreciation as of those dates.

Amounts in US$ '000	Chile	Colombia	Argentina	Brazil	Total
At 31 December 2017					
Proved properties [(a)]					
Equipment, camps and other facilities	80,611	69,906	843	6,036	157,396
Mineral interest and wells	397,031	291,050	11,159	77,264	776,504
Other uncompleted projects [(b)]	12,508	11,290	48	70	23,916
Unproved properties	49,702	4,106	2,975	7,585	64,368
Gross capitalised costs	**539,852**	**376,352**	**15,025**	**90,955**	**1,022,184**
Accumulated depreciation	(253,764)	(228,793)	(5,700)	(39,509)	(527,766)
Total net capitalised costs	**286,088**	**147,559**	**9,325**	**51,446**	**494,418**

(a) Includes capitalised amounts related to asset retirement obligations.

(b) Do not include Peru capitalised costs.

Amounts in US$ '000	Chile	Colombia	Argentina	Brazil	Total
At 31 December 2016					
Proved properties [(a)]					
Equipment, camps and other facilities	80,611	46,785	843	4,174	132,413
Mineral interest and wells	380,037	230,100	4,849	77,255	692,241
Other uncompleted projects	18,274	12,534	36	2,082	32,926
Unproved properties	48,908	4,503	1,894	6,468	61,773
Gross capitalised costs	**527,830**	**293,922**	**7,622**	**89,979**	**919,353**
Accumulated depreciation	(230,917)	(190,025)	(5,692)	(29,803)	(456,437)
Total net capitalised costs	**296,913**	**103,897**	**1,930**	**60,176**	**462,916**

(a) Includes capitalised amounts related to asset retirement obligations and impairment loss reversal in Colombia for US$ 5,664,000.

Amounts in US$ '000	Chile	Colombia	Argentina	Brazil	Total
At 31 December 2015					
Proved properties [(a)]					
Equipment, camps and other facilities	79,040	42,852	843	2,097	124,832
Mineral interest and wells	367,722	213,480	4,849	62,941	648,992
Other uncompleted projects	21,830	7,703	290	-	29,823
Unproved properties	70,062	8,180	-	8,758	87,000
Gross capitalised costs	**538,654**	**272,215**	**5,982**	**73,796**	**890,647**
Accumulated depreciation	(201,138)	(160,759)	(5,654)	(14,236)	(381,787)
Total net capitalised costs	**337,516**	**111,456**	**328**	**59,560**	**508,860**

(a) Includes capitalised amounts related to asset retirement obligations and impairment loss in Chile and Colombia for US$ 104,515,000 and US$ 45,059,000, respectively.

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

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 31 December 2017, 2016 and 2015. Income tax for the years presented was calculated utilizing the statutory tax rates.

Amounts in US$ '000	Chile	Colombia	Argentina	Brazil	Total
Year ended 31 December 2017					
Revenue	32,738	263,076	70	34,238	330,122
Production costs, excluding depreciation					
Operating costs	(19,685)	(42,677)	(325)	(7,603)	(70,290)
Royalties	(1,314)	(24,236)	(13)	(3,134)	(28,697)
Total production costs	**(20,999)**	**(66,913)**	**(338)**	**(10,737)**	**(98,987)**
Exploration expenses [(a)]	(1,404)	(3,856)	(707)	(3,985)	(9,952)
Accretion expense [(b)]	(994)	(683)	-	(930)	(2,607)
Impairment loss reversal for non-financial assets	-	-	-	-	-
Depreciation, depletion and amortization	(22,705)	(38,721)	(8)	(10,659)	(72,093)
Results of operations before income tax	**(13,364)**	**152,903**	**(983)**	**7,927**	**146,483**
Income tax benefit (expense)	2,005	(61,161)	344	(2,695)	(61,507)
Results of oil and gas operations	**(11,359)**	**91,742**	**(639)**	**5,232**	**84,976**

Amounts in US$ '000	Chile	Colombia	Argentina	Brazil	Total
Year ended 31 December 2016					
Revenue	36,723	126,228	-	29,719	192,670
Production costs, excluding depreciation					
Operating costs	(20,674)	(29,326)	-	(5,738)	(55,738)
Royalties	(1,495)	(7,281)	-	(2,721)	(11,497)
Total production costs	**(22,169)**	**(36,607)**	**-**	**(8,459)**	**(67,235)**
Exploration expenses [(a)]	(21,060)	(11,690)	-	(5,636)	(38,386)
Accretion expense [(b)]	(897)	(459)	-	(1,198)	(2,554)
Impairment loss reversal for non-financial assets	-	5,664	-	-	5,664
Depreciation, depletion and amortization	(29,890)	(29,439)	-	(12,785)	(72,114)
Results of operations before income tax	**(37,293)**	**53,697**	**-**	**1,641**	**18,045**
Income tax benefit (expense)	5,594	(21,479)	-	(558)	(16,443)
Results of oil and gas operations	**(31,699)**	**32,218**	**-**	**1,083**	**1,602**

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

Table 3 - Results of operations for oil and gas producing activities (continued)

Amounts in US$ '000	Chile	Colombia	Argentina	Brazil	Total
Year ended 31 December 2015					
Revenue	44,808	131,897	597	32,388	209,690
Production costs, excluding depreciation					
Operating costs	(26,731)	(40,384)	(1,414)	(5,058)	(73,587)
Royalties	(1,973)	(8,150)	(34)	(2,998)	(13,155)
Total production costs	**(28,704)**	**(48,534)**	**(1,448)**	**(8,056)**	**(86,742)**
Exploration expenses [(a)]	(30,499)	(7,132)	(1,159)	(1,103)	(39,893)
Accretion expense [(b)]	(789)	(890)	-	(896)	(2,575)
Impairment loss for non-financial assets	(104,515)	(45,059)	-	-	(149,574)
Depreciation, depletion and amortization	(37,664)	(50,675)	(91)	(13,401)	(101,831)
Results of operations before income tax	**(157,363)**	**(20,393)**	**(2,101)**	**8,932**	**(170,925)**
Income tax benefit (expense)	23,604	7,953	735	(3,037)	29,255
Results of oil and gas operations	**(133,759)**	**(12,440)**	**(1,366)**	**5,895**	**(141,670)**

(a) Do not include Peru costs.

(b) Represents accretion of ARO liability.

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 31 December 2017, 2016 and 2015 was based on the DeGolyer and MacNaughton Reserves Report (the "D&M Reserves Report"). DeGolyer and MacNaughton 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).

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

Table 4 - Reserve quantity information (continued)

Reserves engineering is a subjective process of estimation of hydrocarbon accumulation, which cannot be accurately measured, and the reserve estimation depends on the quality of available information and the interpretation and judgment 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 31 December 2017, 2016 and 2015 are summarised as follows, expressed in thousands of barrels (Mbbl) and millions of cubic feet (MMcf):

	As of 31 December 2017		As of 31 December 2016		As of 31 December 2015	
	Oil and condensate (Mbbl)	Natural gas (MMcf)	Oil and condensate (Mbbl)	Natural gas (MMcf)	Oil and condensate (Mbbl)	Natural gas (MMcf)
Net proved developed						
Chile [(a)]	720.0	8,688.0	547.0	6,610.0	498.0	4,922.0
Colombia [(b)]	21,101.0	-	9,502.0	-	8,177.8	-
Brazil [(c)]	76.0	23,821.0	72.0	29,525.0	120.0	36,158.0
Peru [(d)]	9,502.0	-	9,316.0	-	-	-
Total consolidated	**31,399.0**	**32,509.0**	**19,437.0**	**36,135.0**	**8,795.8**	**41,080.0**
Net proved undeveloped						
Chile [(e)]	3,423.0	11,329.0	6,052.0	29,690.0	5,455.8	31,593.0
Colombia [(f)]	44,398.0	-	27,838.0	-	22,245.5	-
Brazil [(c)]	-	-	-	-	-	-
Peru [(d)]	9,215.0	-	9,305.0	-	-	-
Total consolidated	**57,036.0**	**11,329.0**	**43,195.0**	**29,690.0**	**27,701.3**	**31,593.0**
Total proved reserves	**88,435.0**	**43,838.0**	**62,632.0**	**65,825.0**	**36,497.1**	**72,673.0**

(a) Fell Block accounts for 98% of the reserves (99% in 2016 and 91% in 2015) (LGI owns a 20% interest) and Flamenco Block accounts for 2% (1% in 2016 and 9% in 2015) (LGI owns 31.2% interest).

(b) Llanos 34 Block, Cuerva Block and Yamu Block account for 98%, 1% and 1% (Llanos 34 Block and Llanos 32 Block account for 99% and 1% in 2016, and Llanos 34 Block and Cuerva Block account for 94% and 3% in 2015) of the proved developed reserves, respectively (LGI owns a 20% interest).

(c) BCAM-40 Block accounts for 100% of the reserves.

(d) Morona Block accounts for 100% of the reserves.

(e) Fell Block accounts for 97% of the reserves (99% in 2016 and 100% in 2015) (LGI owns a 20% interest), Flamenco Block accounts for 3% in 2017 (1% in 2016 and nil in 2015) (LGI owns 31.2% interest).

(f) Llanos 34, Cuerva Block and Yamu Block account for 97%, 2% and 1% (Llanos 34 Block accounts for 100% in 2016 and Llanos 34 Block and Cuerva Block account for 95% and 4% in 2015) of the proved undeveloped reserves, respectively (LGI owns a 20% interest).

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

Table 4 - Reserve quantity information (continued)

The amounts of proved reserves disclosed herein as of 31 December 2017 include 13,934.1 thousand barrels of crude oil condensate (8,796.2 in 2016 and 7,281.3 in 2015) and natural gas liquids and 4,317.8 million cubic feet of natural gas (7,356.0 in 2016 and 7,345.8 in 2015) corresponding to non-controlling interest held by LGI.

Table 5 - Net proved reserves of oil, condensate and natural gas

Net proved reserves (developed and undeveloped) of oil and condensate:

Thousands of barrels	Chile	Colombia	Brazil	Peru	Total
Reserves as of 31 December 2014	**6,441.9**	**24,735.3**	**130.0**	**-**	**31,307.2**
Increase (decrease) attributable to:					
Revisions [(a)]	119.0	(225.0)	7.6	-	(98.4)
Extensions and discoveries [(b)]	100.0	10,489.0	-	-	10,589.0
Production	(707.1)	(4,576.0)	(17.6)	-	(5,300.7)
Reserves as of 31 December 2015	**5,953.8**	**30,423.3**	**120.0**	**-**	**36,497.1**
Increase (decrease) attributable to:					
Revisions [(c)]	1,148.0	5,779.0	(34.0)	-	6,893.0
Extensions and discoveries [(d)]	-	6,311.0	-	-	6,311.0
Purchase of Minerals in place [(e)]	-	-	-	18,621.0	18,621.0
Production	(502.8)	(5,173.3)	(14.0)	-	(5,690.1)
Reserves as of 31 December 2016	**6,599.0**	**37,340.0**	**72.0**	**18,621.0**	**62,632.0**
Increase (decrease) attributable to:					
Revisions [(f)]	(2,109.0)	6,315.0	19.0	96.0	4,321.0
Extensions and discoveries [(g)]	-	29,047.0	-	-	29,047.0
Production	(347.0)	(7,203.0)	(15.0)	-	(7,565.0)
Reserves as of 31 December 2017	**4,143.0**	**65,499.0**	**76.0**	**18,717.0**	**88,435.0**

(a) For the year ended 31 December 2015, the Group's oil and condensate proved reserves were revised downwards by 0.1 mmbbl. The primary factors leading to the above were:
- The impact of lower average oil prices resulting in a 2 mmbbl decrease in reserves from the La Cuerva and Yamu blocks in Colombia, and a 1 mmbbl decrease in reserves related to a change in a previously adopted development plan in the Fell Block in Chile.
- Such decrease was partially offset by better than expected performance from existing wells, of which 2 mmbbl was from the Llanos 34 Block in Colombia and 1 mmbbl from the Fell Block in Chile.

(b) In Colombia, the extensions and discoveries are primarily due to the Tilo, Jacana, and Chachalaca field discoveries in the Llanos 34 Block.

(c) For the year ended 31 December 2016, the Group's oil and condensate proved reserves were revised upward by 7 mmbbl. The primary factors leading to the above were:
- Better than expected performance from existing wells, resulting in an increase of 9 mmbbl, of which 8 mmbbl was from the Tigana, Jacana and other minor fields in the Llanos 34 Block, and 1 mmbbl was from the Fell Block in Chile.
- Such increase was partially offset by lower average oil prices impacting the La Cuerva and Yamu blocks in Colombia, resulting in a 2 mmbbl decrease.

(d) In Colombia, the extensions and discoveries are primarily due to the Jacana field appraisal wells in the Llanos 34 Block.

(e) In December 2016, we obtained final regulatory approval for our acquisition of the Morona Block in Peru. The Joint Investment and Operating Agreement dated 1 October 2014 and its amendments were closed on 1 December 2016 following the issuance of Supreme Decree 031-2016-MEM.XXX.

(f) For the year ended 31 December 2017, the Group's oil and condensate proved reserves were revised upward by 4.3 mmbbl. The primary factors leading to the above were:
- Better than expected performance from existing wells, from the Tigana and Jacana fields in the Llanos 34 Block, resulting in an increase of 3.8 mmbbl.
- The impact of higher average oil prices resulting in a 2.5 mmbbl and 0.4 mmbbl increase in reserves from the blocks in Colombia and Chile, respectively.
- Such increase was partially offset by a decrease in reserves mainly related to a change in a previously adopted development plan in the Fell Block in Chile, resulting in a 2.4 mmbbl decrease.

(g) In Colombia, the extensions and discoveries are primary due to the Chiricoca, Jacamar, and Curucucu field discoveries in the Llanos 34 Block and the Tigana and Jacana field extentions in the Llanos 34 Block.

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

Table 5 - Net proved reserves of oil, condensate and natural gas (continued)

Net proved reserves (developed and undeveloped) of natural gas:

Millions of cubic feet	Chile	Brazil	Total
Reserves as of 31 December 2014	**33,970.0**	**40,464.0**	**74,434.0**
Increase (decrease) attributable to:			
Revisions [a]	(2,807.6)	2,907.0	99.4
Extensions and discoveries [b]	9,378.0	-	9,378.0
Production	(4,025.4)	(7,213.0)	(11,238.4)
Reserves as of 31 December 2015	**36,515.0**	**36,158.0**	**72,673.0**
Increase (decrease) attributable to:			
Revisions [c]	5,078.0	(319.0)	4,759.0
Production	(5,293.0)	(6,314.0)	(11,607.0)
Reserves as of 31 December 2016	**36,300.0**	**29,525.0**	**65,825.0**
Increase (decrease) attributable to:			
Revisions [d]	(13,725.0)	59.0	(13,666.0)
Extensions and discoveries [e]	1,187.0	-	1,187.0
Production	(3,745.0)	(5,763.0)	(9,508.0)
Reserves as of 31 December 2017	**20,017.0**	**23,821.0**	**43,838.0**

(a) For the year ended 31 December 2015, the Group's proved natural gas reserves were revised by 0.1 billion cubic feet. This was the combined effect of:
- Better than expected performance from existing wells that resulted in an increase of 13 billion cubic feet (3 billion cubic feet from the Manati field in Brazil and 10 billion cubic feet from the Fell Block in Chile).
- The above was partially offset by a decrease of 13 billion cubic feet due to lower average gas prices in the Fell and Tierra del Fuego (TdF) blocks in Chile (totalling 3 billion cubic feet) and changes in previously adopted development plan in the Fell Block in Chile (totalling 10 billion cubic feet).

(b) In Chile, the extensions and discoveries are primary due to the Ache Field discovery and from the extension well in the Fell Block.

(c) For the year ended 31 December 2016, the Group's proved natural gas reserves were revised upwards by 5 billion cubic feet. This increase was mainly driven by better than expected performance from existing wells, primarily the Ache field in the Fell Block in Chile, resulting in an addition of 9 billion cubic feet. This increase was partially offset by a reduction of 4 billion cubic feet in the Pampa Larga field, also in the Fell Block.

(d) For the year ended 31 December 2017, the Group's proved natural gas reserves were revised downwards by 13.7 billion cubic feet. This was the combined effect of:
- Removal of proved undeveloped reserves due to changes in previously adopted development plan in the Fell Block in Chile and unsuccessful proved undeveloped executions in the Fell Block in Chile (totalling 21.3 billion cubic feet).
- The above was partially offset by an increase of 6.8 billion cubic feet due to a better performance in the proved developed producing reserves in the Fell Block in Chile and the impact of higher average prices that resulted in an increase of 0.8 billion cubic feet.

(e) In Chile, the extensions and discoveries are primary due to the Uaken Field discovery in the Fell Block.

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.

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

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 2017, 2016 and 2015 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.

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

Table 6 - Standardized measure of discounted future net cash flows related to proved oil and gas reserves (continued)

Amounts in US$ '000	Chile	Colombia	Brazil	Peru	Total
At 31 December 2017					
Future cash inflows	284,711	2,434,954	157,527	1,047,540	3,924,732
Future production costs	(131,788)	(531,751)	(56,311)	(466,110)	(1,185,960)
Future development costs	(57,690)	(187,414)	(7,524)	(235,920)	(488,548)
Future income taxes	(656)	(558,226)	(10,442)	(107,294)	(676,618)
Undiscounted future net cash flows	**94,577**	**1,157,563**	**83,250**	**238,216**	**1,573,606**
10% annual discount	(19,338)	(343,561)	(13,293)	(147,682)	(523,874)
Standardized measure of discounted future net cash flows	**75,239**	**814,002**	**69,957**	**90,534**	**1,049,732**
At 31 December 2016					
Future cash inflows	394,993	873,771	200,713	941,463	2,410,940
Future production costs	(186,700)	(229,593)	(74,116)	(497,187)	(987,596)
Future development costs	(149,785)	(69,996)	(16,352)	(234,328)	(470,461)
Future income taxes	(8,344)	(191,096)	(21,041)	(69,698)	(290,179)
Undiscounted future net cash flows	**50,164**	**383,086**	**89,204**	**140,250**	**662,704**
10% annual discount	(14,709)	(113,584)	(15,688)	(109,321)	(253,302)
Standardized measure of discounted future net cash flows	**35,455**	**269,502**	**73,516**	**30,929**	**409,402**
At 31 December 2015					
Future cash inflows	403,199	1,032,339	221,206	-	1,656,744
Future production costs	(186,933)	(309,394)	(99,832)	-	(596,159)
Future development costs	(112,312)	(99,305)	(16,360)	-	(227,977)
Future income taxes	(17,904)	(195,957)	(16,837)	-	(230,698)
Undiscounted future net cash flows	**86,050**	**427,683**	**88,177**	**-**	**601,910**
10% annual discount	(17,895)	(127,586)	(15,861)	-	(161,342)
Standardized measure of discounted future net cash flows	**68,155**	**300,097**	**72,316**	**-**	**440,568**

Note

37 Supplemental information on oil and gas activities (unaudited – continued)

Table 7 - Changes in the standardized measure of discounted future net cash flows from proved reserves

Amounts in US$ '000	Chile	Colombia	Brazil	Peru	Total
Present value at 31 December 2014	**227,658**	**584,071**	**112,145**	**-**	**923,874**
Sales of hydrocarbon , net of production costs	(20,948)	(97,152)	(37,428)	-	(155,528)
Net changes in sales price and production costs	(256,828)	(547,379)	(27,404)	-	(831,611)
Changes in estimated future development costs	28,227	(20,123)	542	-	8,646
Extensions and discoveries less related costs	23,595	174,951	-	-	198,546
Development costs incurred	15,093	29,965	4,872	-	49,930
Revisions of previous quantity estimates	(5,463)	(14,528)	4,845	-	(15,146)
Net changes in income taxes	28,611	101,576	1,573	-	131,760
Accretion of discount	28,210	88,716	13,171	-	130,097
Present value at 31 December 2015	**68,155**	**300,097**	**72,316**	**-**	**440,568**
Sales of hydrocarbon , net of production costs	(15,127)	(91,163)	(20,945)	-	(127,235)
Net changes in sales price and production costs	(16,854)	(171,131)	16,366	-	(171,619)
Changes in estimated future development costs	(49,763)	14,941	542	-	(34,280)
Extensions and discoveries less related costs	-	76,641	-	-	76,641
Development costs incurred	9,417	17,302	2,214	-	28,933
Revisions of previous quantity estimates	22,765	70,180	(1,872)	-	91,073
Purchase of Minerals in place	-	-	-	30,929	30,929
Net changes in income taxes	8,256	3,030	(4,020)	-	7,266
Accretion of discount	8,606	49,605	8,915	-	67,126
Present value at 31 December 2016	**35,455**	**269,502**	**73,516**	**30,929**	**409,402**
Sales of hydrocarbon , net of production costs	(14,251)	(198,631)	(26,979)	-	(239,861)
Net changes in sales price and production costs	26,928	289,199	(3,000)	69,962	383,089
Changes in estimated future development costs	79,078	(124,053)	8,385	(9,725)	(46,315)
Extensions and discoveries less related costs	-	49,574	-	-	49,574
Development costs incurred	7,146	67,571	-	-	74,717
Revisions of previous quantity estimates	(69,594)	673,622	603	1,133	605,764
Purchase of Minerals in place					
Net changes in income taxes	6,097	(258,842)	7,976	(11,828)	(256,597)
Accretion of discount	4,380	46,060	9,456	10,063	69,959
Present value at 31 December 2017	**75,239**	**814,002**	**69,957**	**90,534**	**1,049,732**

The amounts of the standardized measure of discounted future net cash flows herein for the year ended 31 December 2017, 2016 and 2015 include $178.1 million, $61.4 million and $73.9 million that correspond to the non-controlling interest held by LGI.