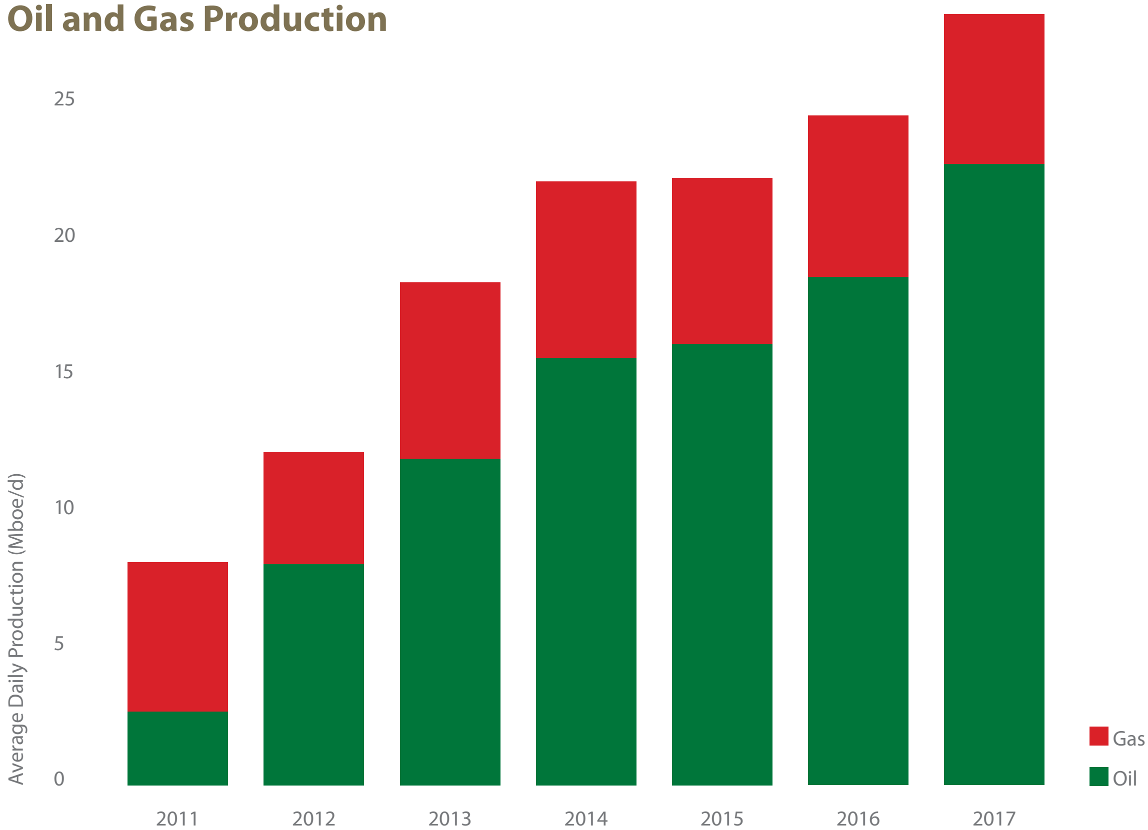
ANNUAL REPORT 2017

GEOPARK

EXPLORER OPERATOR CONSOLIDATOR

CONTENTS

Oil and Gas Production



Oil and Gas Reserves

Magallanes Region, Chile

"As an entrepreneurial and battle-tested company that has grown from scratch into one of Latin America's leading independents, we attribute our success to a proud culture based on trust - and which is the catalyst for our continuous record of safe, clean, neighborly, transparent, and successful operations"

Dear Fellow Shareholders:

We are pleased to report that our GeoPark team again outperformed in 2017 – making us a better, stronger, more capable, and more valuable Company than ever before.

The international investment community began taking increased notice of our enduring growth track record and GeoPark was the best performing upstream oil and gas company on the New York Stock Exchange in 2017 with a 130% share price increase.

A continuous theme of GeoPark is '*Vamos por Más*' ('Let's Go for More') and our 2017 performance delivered *más* (more) in all key fundamentals of our business:

Más **Oil and Gas**

Success in our industry begins by being able to consistently find, develop and produce oil and gas. Last year, GeoPark extended its exceptional 15 year growth track record and increased production by 23% to a record 27,586 boepd with an exit production of 31,977 boepd. In Colombia, production grew by 39% to 21,787 boepd. After producing over 10 million boe during the year, we replaced and grew our certified oil and gas reserves with proven (1P) reserves increasing by 24% to 97 million boe and total proven and probable (2P) reserves increasing by 11% to 159 million boe. In Colombia, 2P reserves increased by 31% from the continuing extension of the large Tigana and Jacana oil fields.

Más **Efficiencies / Lower Costs**

Being the safest lowest-cost driller and producer of oil and gas are the critical factors in achieving long-term industry leadership and economic success - with an even greater emphasis in today's world of oil price volatility. GeoPark's operational strength has allowed us to relentlessly drive down capital and operating costs to achieve top-performing metrics, with 2P finding and development costs of $4.0 per boe (consolidated) and $2.8 per boe (Colombia), and operating costs of $7.3 per boe (consolidated) and $4.3 per bbl (Colombia Llanos 34). Our passion for cost efficiency has resulted in 90% of GeoPark's production being cash flow positive at oil prices of just $25-30 per barrel.

Más **Cash / Capital Strength**

Differentiating us from most of our industry peers, GeoPark is a self-funding growing cash-generating company - meaning our own cash flows are sufficient to pay for and expand our business. Cash flows from operating activities were up 72% to $142 million and Adjusted EBITDA more than doubled to $176 million. We also successfully lowered borrowing costs and extended debt maturities by issuing a new bond for $425 million, at 6.5% due in 2024, and which was substantially oversubscribed by top tier international investors. We closed 2017 with $135 million in cash.

Más **Value**

With our new oil and gas discoveries in 2017 and increasingly-efficient cost structure, the independently-certified net present value (NPV) of GeoPark's 2P oil and gas reserves increased by 21% to a value of $2.3 billion (despite using lower price decks compared to 2016). Last year we invested $106 million and increased our NPV by $404 million. On a 'per share' basis and deducting outstanding net debt and minority interests, our net debt adjusted 2P NPV per share increased by 24% to $29.2 per share (or $15.8 per share for Colombia alone). This means our market share price is still significantly below the underlying value of our oil and gas assets.

Más **Acreage / Upside**

GeoPark has steadily and economically built an extensive land position across Latin America – with more than five million acres in 29 blocks in 9 proven hydrocarbon basins in 5 countries, consisting of a risk-balanced mix of production, development, exploration and unconventional resource projects. This large acreage platform is one of our most powerful assets – one that does not show up on a balance sheet – but which provides the foundation for long-term growth. On our acreage, GeoPark has identified new geological plays and prospects – that is, new potential oil and gas fields – with audited exploration resources of 700 million to 1.3 billion boe.

Más **Opportunity**

One of the pillars of GeoPark's business plan is our success in identifying and acquiring new high-quality projects on attractive terms. Our continuous efforts to uncover new business opportunities over the last 10+ years in targeted hydrocarbon basins has built a

Jacana Field, Llanos 34 Block, Colombia

$2+ billion new project inventory in Colombia, Brazil, Argentina, Peru, Ecuador and Mexico – with an active focus on initiatives with Latin American national oil companies. In early 2018, GeoPark entered into a new acquisition partnership with ONGC, the national oil company of India, to support and join our efforts to expand our upstream portfolio across Latin America.

Más Capabilities

Our big ambitions require us to prepare for our future by continuously investing in our capacities and know-how and to become the best at every component of our business. Last year we continued to invest in our technical, financial and management excellence and strengthen our country business unit teams, including new leadership in Peru and Argentina. This includes dynamically structuring our organizational and leadership framework to more effectively manage our growing enterprise and capture the future.

Más Safe, Clean and Neighborly Operations

Our in-house-designed value system called SPEED is GeoPark's competitive advantage. SPEED represents our character, guides our behavior and defines our success. It creates positive interdependence with the communities where we operate and ensures safe and environmentally-clean operational performance – with the goal to be the partner-of-choice, employer-of-choice and neighbor-of-choice. From 2015 to date, GeoPark is the only major operator in Colombia with zero work interruptions. In 2017, GeoPark was awarded the ISO 14001 environmental management certification in Colombia.

Vision and Alignment

As described in our Business Guidelines which accompany every Annual Report, GeoPark's long-term value proposition is to build the leading oil and gas independent company in Latin America – a region of unlimited hydrocarbon resources, a welcoming business environment, and little competition. An advantage in creating our Company has been a consistent long-term vision and conservative business plan that are supported and shared by our shareholders, Board of Directors, management and employee team.

It is our steady focus on this bigger prize that has allowed us to build the foundation and tools needed for the long-term and to push forward regardless of any short-term cycles or sentiment. We believe our strength and unique position across the region today results from this alignment and gives us even more advantages in achieving our ambitious goals.

People

As our history has proved, great people create great results. We are pleased to recognize and thank the women and men who have built and are continuing to build GeoPark. They are our heart and engine, and have faced and met every challenge with a professionalism, creativity and agility that keeps propelling us forward.

As an entrepreneurial and battle-tested company that has grown from scratch into one of Latin America's leading independents, we attribute our success to a proud culture based on trust – and which is the catalyst for our continuous record of safe, clean, neighborly, transparent and successful operations.

Our gratitude extends to the persistently supportive families of all our team members who have contributed immensely to where we have been and where we are going. We were fortunate to join with all employees and spouses this year for GeoPark's Fifteenth Anniversary to express our thanks personally and to celebrate together our powerful culture, impressive accomplishments and big expectations for each other.

A special thanks also to our hard-working Board of Directors. We are saddened by the unfortunate passing of Peter Ryalls and Michael Dingman and sincerely grateful for their important and valuable contribution to our Company.

Business Platform

GeoPark's business plan follows a technical approach to identify high-value under-exploited proven hydrocarbon basins – based on geological, infrastructure and regulatory factors. We then work to establish strategic positions in the targeted regions. Our systematic expansion to date has resulted in building stable and growing businesses in Colombia, Chile, Brazil, Argentina and Peru. Each country is managed by reputable and professional local teams, with

supporting production and cash flows, attractive underlying reserves and resources, and inventories of new project opportunities.
Our independent country businesses are further enhanced by being supported by an overall corporate organization, which improves efficiencies, reduces costs through operational and financial synergies, controls quality, drives performance, and more effectively grows our overall company by allocating capital to the best shareholder value-adding projects.

Briefly looking at each of our businesses:

Colombia Business

GeoPark is leading the strongest upstream project in Colombia and one of the most attractive onshore projects in Latin America today. In less than five years we grew from zero to be the third largest oil operator in the country – and are currently proving up what is being called the largest oil field discovery in Colombia in the last 20 years.

Our key asset is the Llanos 34 Block (GeoPark operated), which we have grown from 0 to 50,000+ bopd gross production. During 2017, following successful appraisal drilling in the Tigana and Jacana oil fields and new oilfield discoveries – Curucucu, Chiricoca, and Jacamar – we materially increased our Colombian certified 1P and 2P reserves by 64% and 31% to 66 million boe and 88 million boe respectively. Our 2P reserve life index reached 11 years and the reserve replacement ratio was 360%. Our 1P NPV and 2P NPV in Colombia increased to $1.1 billion and $1.4 billion respectively.

Llanos 34 is a highly-attractive, low risk, low cost and high netback block which provides a large scale profitable production base even in low oil price environments. Due to the expertise of our local teams, net finding and development costs (F&D costs) for 2017 were just $2.4 per boe (1P). We have a big inventory of well sites (75+) to continue growing production, with IRRs exceeding 500% and six-month paybacks (assuming a $50 per barrel Brent oil price). Our economics and return on capital in Llanos 34 are highly profitable and beat almost any North American conventional or unconventional play.

In a constant effort to reduce transportation costs and improve netbacks, we are constructing a new 30 km flow line to connect Llanos 34 to the main Colombian pipeline infrastructure.

During 2017, GeoPark also acquired attractive exploration acreage (Tiple and Zamuro), adjacent to Llanos 34, by farming-in with a commitment to drill two exploration wells in 2018.

Argentina Business

Our team is continuing to strengthen our position in Argentina, where it has a proven history of exploration success.

In August 2017, we made a successful new light oil field discovery with the Rio Grande Oeste exploration well in the CN-V Block in the Neuquen Basin. An adjacent prospect will be drilled in 2018.

In December 2017, GeoPark acquired a 100% working interest in and operatorship of three new blocks (Aguada Baguales, El Porvenir and Puerto Touquet) in the heart of the Neuquen Basin with production, development, exploration and unconventional resource potential. The blocks are currently producing 2,400-2,500 boepd and were acquired at a value of $4 per boe 2P reserves. In addition to its attractive upside potential, this acqusition represents a good fit with our existing platform in Argentina with cost savings and operational synergies.

Peru Business

GeoPark continues working to prepare for the development of the Morona Block. This project has become emblematic for Peru and represents PetroPeru's return to upstream activity. GeoPark was selected as the partner-of-choice and awarded the operatorship with a 75% working interest. We recently signed a cooperation agreement with the local indigenous communities to work together to complete the Environmental Impact Assessment which is expected to be submitted in 2018.

Morona is a large block in the proven Maranon Basin with a large upside potential (approximately 320-500 million boe) with several high impact plays and prospects. The block's key asset is the Situche Central oil field, which was discovered and proven up by two wells (which tested at a combined rate of 7,500 bopd), and which has certified gross 3P reserves of 83 million barrels, a big 200 million barrel potential, and the opportunity for near-term cash flow. Morona represents an important acquisition for GeoPark that significantly increases our overall inventory of reserves and exploration resources and can contribute to our long-term durable growth. GeoPark has designed a phased work program that is expected to put the Situche Central field into production initially through a long-term test to begin generating cash flow – with 'first oil' targeted for 2019.

Magallanes Region, Chile

Brazil Business

Our Brazil business represents a strategic base with a fully-developed, secure, cash flow-producing asset (a non-operated interest in the Manati field, one of Brazil's largest producing gas fields, operated by Petrobras) and 8 exploration blocks in onshore mature proven hydrocarbon basins (Potiguar, Reconcavo, and Sergipe Alagoas). GeoPark will drill 2-3 exploration wells in 2018 to continue testing this potential.

GeoPark also has identified attractive onshore hydrocarbon opportunities in Brazil and is working with Petrobras in its divestment efforts with the objective of expanding our asset base.

Chile Business

We are Chile's first private oil and gas producer. We built the business from a flat-footed start-up in 2006 to a solid business with current production of approximately 2,900 boepd (66% gas, 34% oil), 2P reserves of 34 million boe and 5 blocks with 0.8 million acres, consisting of approximately 375-700 million boe of exploration and unconventional resources. Over 20 million boe have already been produced by GeoPark in Chile and we divested 20% of our project in 2011 for approximately $150 million.

Our Chilean team has done an excellent job improving efficiencies and maintaining production stability with very little new investment. Production and reserves decreased in 2017 due the natural decline of the fields and limited drilling activity since the end of 2014. In early 2017, GeoPark extended its gas off-take contract with Methanex to 2026 to supply its large methanol plant in Punta Arenas.

In early 2018, GeoPark drilled and tested a new shallow El Salto formation prospect and discovered the Uaken gas field; which creates a new low cost gas play across the Fell Block.

New Projects and Countries

With our focus on achieving scale, GeoPark is always in the hunt to acquire attractively-valued new oil and gas upstream opportunities across Latin America and we have built an impressive inventory of new projects over the last ten years. Following the lower oil price environment, national oil companies, which control the biggest and best hydrocarbon acreage, are reevaluating their portfolios and initiating divestment programs. Our regional platform, expertise and reputation give us first mover advantage in potentially acquiring these attractive projects.

We are also working towards establishing new platforms in Mexico and Ecuador, where regulatory reforms have opened the door for private companies to access highly attractive hydrocarbon assets – many of which are an excellent fit for GeoPark's skill set.

As a result of our existing large and diversified organic asset portfolio, GeoPark has the advantage of being a patient asset acquirer, and can wait for the right market opportunities to acquire the right projects at the right prices. To enhance our position as the preferred buyer in the region, we have also created strategic acqusition partnerships with strong players, such as ONGC from India.

Tua Field, Llanos 34 Block, Colombia

Outlook

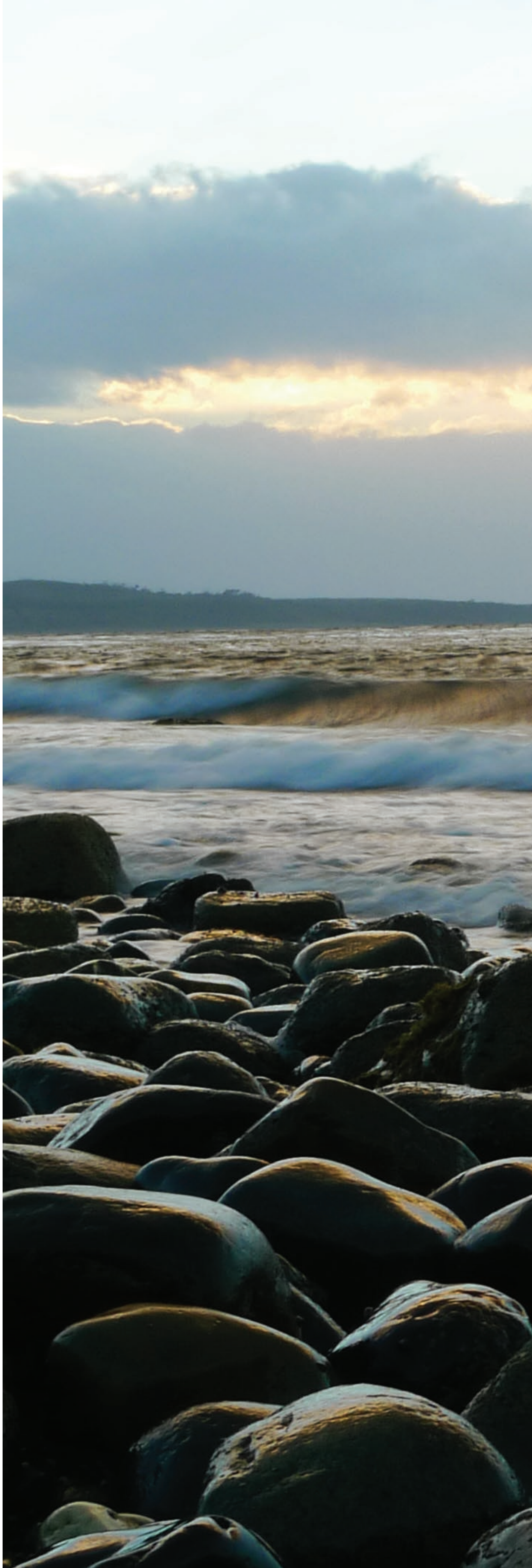
As a Company, GeoPark is built to prosper in a $40-45 oil price world. The current increased price environment allows us to further expand our programs and achieve greater returns – while maintaining our inherent discipline and focus on cost and value.

Our 2018 work and investment program targets a $140-150 million capital investment program (considering Brent oil prices of $60 per barrel), and is fully funded by operating cash flows.

The work program provides for a 40+ well drilling program targeting production growth of 25-30% (including the new Argentine assets) and an exit production of 38,000-39,000 boepd, and includes:

- 29-31 gross well development, appraisal and exploration drilling program and new flowline construction in the Llanos 34 and adjacent blocks in the Llanos Basin in Colombia
- 6-7 gross well exploration drilling program in the Neuquen Basin in Argentina
- Environmental impact assessment and preliminary engineering and facility work on the Morona Block in the Maranon Basin in Peru
- 2-3 gross well exploration drilling program in the onshore Reconcavo and Potiguar Basins in Brazil
- 1-2 gross well exploration and development drilling program on the Fell Block in the Magallanes Basin in Chile

GeoPark has developed and proven-up a highly-effective capital allocation methodology to manage its five country portfolio. This system enables us to review and select from a wide range of projects generated by each business unit team with different returns, potentials, risks, sizes, timelines and geographies. It ensures that capital is always directed to our top value-adding projects after ranking them on technical, strategic and economic criteria. It creates a healthy competition between our different business units which further helps drive performance. It also provides greater security in volatile markets by allowing us to easily add or remove projects depending on oil prices and project performance – and to fine-tune our desired risk exposure.



Thank You

Our sincere thanks and appreciation to our shareholders and bondholders – old and new alike – who have partnered with us, believe in our project, and support our efforts. In 2017, we continued our campaign to reach out to new investors and better align our market value with the underlying asset value we have unlocked in the field. As a result, we were the leading E&P stock performer last year and our stock trading volumes have begun to accelerate (now at levels exceeding $5 million per day) which has opened up shareholder participation to the wider investment community.

As always, your comments and recommendations are welcomed and appreciated. We please invite you to visit us in the field or at any of our offices to get to know us better and learn first-hand how we work.

We look forward to delivering and reporting to you on our results in 2018.

Sincerely,

Gerald E. O'Shaughnessy
Chairman

James F. Park
Chief Executive Officer









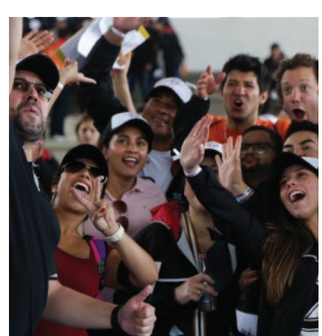
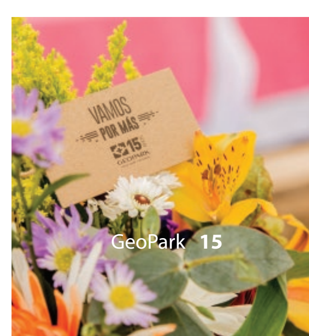








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BUSINESS APPROACH AND GUIDELINES

Strategic Context

GeoPark's objective is to create value by building the leading Latin American upstream independent oil and gas company. By this, we mean an action-oriented, persistent, aware and caring company with the best 'shareholder value-adding' oil and gas assets.

We believe the energy business – specifically the upstream oil and gas industry – is one of the most exciting, necessary, and economically-rewarding businesses today. No undertaking or society can advance without the supply of energy, and energy remains the critical element in allowing people to better their lives. Much of the world still lacks adequate energy supplies for the most basic needs and demand is continually increasing. Although new exciting technologies and sources are being developed, oil and gas is the most reliable energy source and will be required to support over half of our planet's continuous and rising energy needs far into this century.

We believe the best places for us to find and develop hydrocarbons are in areas around the world where oil and gas have already been discovered, but which for economic, technical, funding or other reasons have been inadequately developed or prematurely abandoned. These projects have proven hydrocarbon systems, valuable technical information, existing infrastructure, and, in many cases, unexploited low-risk exploration and re-development opportunities. By applying new technology and investment, creating stable markets and better economic conditions, and/or more efficient operations, an under-performing or bypassed asset can be converted into an attractive economic project. Work in these proven areas also frequently opens up exciting new hydrocarbon resources in new geological play types and formations.

We are focused on Latin America because of the abundance of these types of opportunities throughout the region. Latin America ranks as one of the highest potential hydrocarbon resource regions in the world and its economies are thirsty for new energy. Historically, it has been dominated by larger major and national oil companies, with the presence of only a modest number of more-agile independent companies. North America is home to thousands of independent oil and gas operators, whereas Latin America, an area substantially larger and with greater resource potential, has only a handful of independents taking advantage of available opportunities. In contrast to many areas of the world, the environment and resources for operating and funding a business are welcoming and increasingly more feasible. Furthermore, numerous good oil and gas assets in Latin America are available, undervalued and at very attractive prices now.

GeoPark has been conservatively built for the long-term. We did not

start with a short term 'exit strategy' in mind and we have focused on building a team and sustainable business. Our approach has required patience in order to create the necessary foundation, but it has enabled us to stay solidly ' in the game' and be positioned to now have the chance to grab the bigger prizes.

The founders and our management team have a substantial part of our net worth invested in GeoPark. (The CEO founder has never sold a share of GeoPark stock.) The management team has no special class of stock or arrangements that benefit us differently from any other shareholder other than our salaries and stock performance incentive programs. The entire GeoPark team (100% of our employees have received GeoPark share awards) is solidly aligned with all of our shareholders to build real and enduring value for every share of GeoPark.

Opportunity Enhancement and Risk Diversification

By its very nature, the upstream oil and gas business represents the undertaking of risk in search of significant rewards. To succeed, an oil and gas company must effectively identify and manage prevailing risks and uncertainties to capture the available rewards. We believe this to be one of GeoPark's key capabilities; and our year-over-year track record is evidence of our success in effectively balancing risk among the subsurface, geological, funding, organizational, market, price, partner, shareholder, regulatory and political environments. For example, GeoPark was able to respond constructively to the 2008/9 financial crisis and, again, to the oil volatility of 2015-2016.

We believe the best results in the upstream business are achieved with a larger scale portfolio approach with multiple attractive projects in multiple regions managed by talented oil and gas teams. This diversification reflects both a defensive and offensive approach. It is protective of any downside because the collective strength of our projects limits the negative impact of any underperforming asset or timing delay. It also has an exciting multiplier effect on the potential upside because of the increased number of opportunities independently marching ahead. These represent important advantages given the nature of the oil exploration and production business.

Our country businesses are managed by experienced local professionals and teams with respected reputations. They know both the specific subsurface rocks and conditions and the above-ground operating and business environments in each region and give us the characteristics of a local company. Our pride and care in how we act

Casanare Department, Colombia

and perform in our home regions are key elements of our success.

These generally independent businesses are further enhanced by being tied together by an overall corporate organization, which improves efficiencies, reduces costs with operational and financial synergies, controls quality, and can more effectively raise capital for our projects. It is also a source for new technologies and ideas to spread from one region to another. For example, our team introduced a new geological play-type to the Llanos Basin in Colombia (an area that has been explored for more than 75 years) that resulted in multiple new oil field discoveries, and new oil technology to the Magallanes Basin in Chile.

Importantly, through effective and controlled capital allocation, our projects within each country business can be ranked against each other on economic, technical and strategic criteria and, therefore, ensure our capital resources flow to the highest performing and most attractive projects.

We believe this business approach makes GeoPark a more attractive investment vehicle for all our shareholders – with a strong foundation to minimize any downside, a big upside through multiple growth opportunities, and an overall organizational system to more efficiently run and grow the individual businesses. GeoPark's model allows our investors to be exposed to and benefit from the results of multiple supporting and aligned businesses across diverse geologies and geographies.

Capabilities

Our experience in the oil and gas business has repeatedly demonstrated the need for good people with commitment and real oil and gas know-how. We believe in and have experienced the amazing capacity of people to excel in an environment of expanding opportunity and trust. GeoPark is blessed to have an incredible group of men and women who truly work day and night to make us better in every way. Our results speak to the daily heroics (mostly unseen) of our team that keep us together and have moved us consistently closer to our goals.

Our record of delivery is based on three fundamental and distinct skill sets – as Explorers, Operators and Consolidators – which we deem critical for enduring success in the oil and gas business. Our team has consistently demonstrated the science and creativity to find hydrocarbons in the subsurface, but also the muscle and experience to get the oil and gas out of the ground and profitably to market. Our attractive asset portfolio is evidence of our ability to acquire good projects in the right basins in the right countries with the right partners and at the right price.

Today, we have an amazing team of employees from Chile, Colombia, Brazil, Peru and Argentina – each of whom joined GeoPark with the purpose of building a unique and special company that is prepared to handle challenges and seize opportunities. As a quickly growing company, we have repeatedly seen individuals step-up to the new responsibilities presented – and we have a deep and powerful leadership team taking GeoPark to the next level.

The international upstream oil and gas business is not for the fainthearted or easily discouraged. Time-after-time, the GeoPark team has been able to push ahead to find solutions where often others have given-up or failed. This is the engine and fire of our growth and the true long-term intangible value of our Company. We are immensely grateful to all these men and women for their professionalism, discipline, unity and heart.

New Projects and Countries

We are excited about potential new business opportunities in Latin America with its high resource potential, attractive business environment, and limited competition. We are actively pursuing new projects in targeted proven hydrocarbon basins throughout the region – selected in consideration of geological, infrastructure and regulatory factors – with our principal efforts in Colombia, Brazil, Chile, Peru, Argentina, and Mexico.

With our overall growth targets and portfolio approach, new project acquisitions are an important part of our business. Our acquisition efforts begin with a technical approach to define the hydrocarbon basins where our geological and engineering teams identify an attractive potential. After screening for political risks, our new business teams proactively 'scratch and dig' to locate interests or opportunities within those areas and to establish a position. It is a long-term and continuous effort and we have been building an

Tua Field, Llanos 34 Block, Colombia

Morona River, Morona Project, Peru

attractive inventory of new projects in the region over the last ten years, aided by our team's 25+ year experience in Latin America.

Our focus is always to build a larger scale balanced portfolio that includes lower-risk short term cash flow generating properties, mid-term medium-risk development projects, and longer-term higher-risk big upside projects. This permits steady secure growth with an opportunity for accelerated high growth 'home-runs' from the bigger projects.

Good oil and gas partners are a key element of our new business efforts and we like to balance our acquisition risk by including experienced partners in our new projects. We have developed a long-term strategic alliance with ONGC to build a portfolio of upstream assets across Latin America and the International Finance Corporation (IFC) of the World Bank is a long-term principal shareholder of (and sometimes lender to and working interest partner of) GeoPark. We also have developed long-term relationships with the national oil companies where we operate, such as ENAP in Chile, Ecopetrol in Colombia, Petrobras in Brazil, YPF in Argentina and Petroperu in Peru.

Critical to the success of any new project is to conduct a thorough technical and economic analysis prior to acquiring any new asset. We make sure we understand the project, its risks and its value – and we buy right. It is difficult to turn a faulty or overpriced project into a good business. Following intensive geological, geophysical, engineering, operational, legal and financial analyses and due diligence, we perform a detailed discounted cash flow (DCF) valuation. We also consider the option value or strategic benefits of a project when entering a new region. We do not buy assets on simplified '$ per barrel' metrics which we believe do not properly account for multiple factors (including technical, cost, tax, and time) that impact the economics of oil and gas projects. We also avoid markets or 'bubbles' when assets are over-priced.

Culture

'Creating Value and Giving Back' is our motto and represents GeoPark's market-based approach to align our business objectives with our core values and responsibilities. Our in-house designed program, titled SPEED, targets and integrates the critical elements – Safety, Prosperity, Employees, Environment and Community Development – necessary to make our total business plan work. Only by succeeding equally in each of these interdependent areas can we realize our overall success and ambitions. This is important in every country where we operate, and we make every effort to achieve the most effective governance, full compliance and consistent transparency with all relevant authorities. Not only does this allow us to be a more successful business enterprise over the long-term, it reflects our pride in carrying out an important mission in the right way. The men and women of GeoPark care passionately about how our Company acts – both internally and externally – and we all consider our culture to be our core asset and the prime source of our past success and future opportunity.

The world is continuously moving in a more regulated direction with higher expectations, and to be able to operate in this new environment is a fundamental part of business today. We believe that GeoPark's ability to meet these challenges and perform to or beyond these ever increasing standards represents a competitive advantage for the future. For example, the manner of, results from, and impact on the communities of our overall work in Chile and Colombia provided the rationale and support for the government and regional community to allow us to expand our project into new areas. It can also be meaningful and fun, such as with our full scholarships targeting young women, in the local communities near our field operations, for training in the sciences.

The IFC of the World Bank, our long time shareholder, has been a constructive force in helping us operate and manage our business in consideration of the environment and communities around us. The IFC further assists us by carrying out annual audits and physical site visits of both our regulatory compliance and best-practices approach.

- James F. Park (2008*)

Record Oil and Gas Production

- Production up 23% to 27,586 boepd.
- Colombia production up 39% to 21,788 bopd.
- Record exit production of 31,977 boepd.

Record Oil and Gas Reserves

- 1P reserves up 24% to 97.0 million boe.
- 2P reserves up 11% to 159.2 million boe.
- Colombia 2P reserves up 31% to 88.2 million boe.

Record Oil and Gas Asset Valuation

- 1P reserve NPV10 up 38% to $1.5 billion.
- 2P reserve NPV10 up 21% to $2.3 billion.
- 2P reserve Colombian assets NPV10 up 38% to $1.4 billion.
- Net debt adjusted 2P NPV10 increased by 24% to $29.2 per share.

Record Capital Investment and Costs Efficiencies

- 2P Finding and development costs: Consolidated $4.0/boe; Colombia $2.8/boe.
- Operating netback/capital expenditure ratio of 2.2x.
- Capital investment program of $105.6 million generated $404 million in 2P NPV10.
- OPEX: $7.3 per boe, Colombia $5.6 per boe.

Record Cash Flow/EBITDA Growth

- Adjusted EBITDA up 124% to $175.8 million.
- Operating Netback up 87% to $228.3 million.
- Cash Flow from operations up 72% to $142.2 million.

Strengthened Balance Sheet and Credit Rating

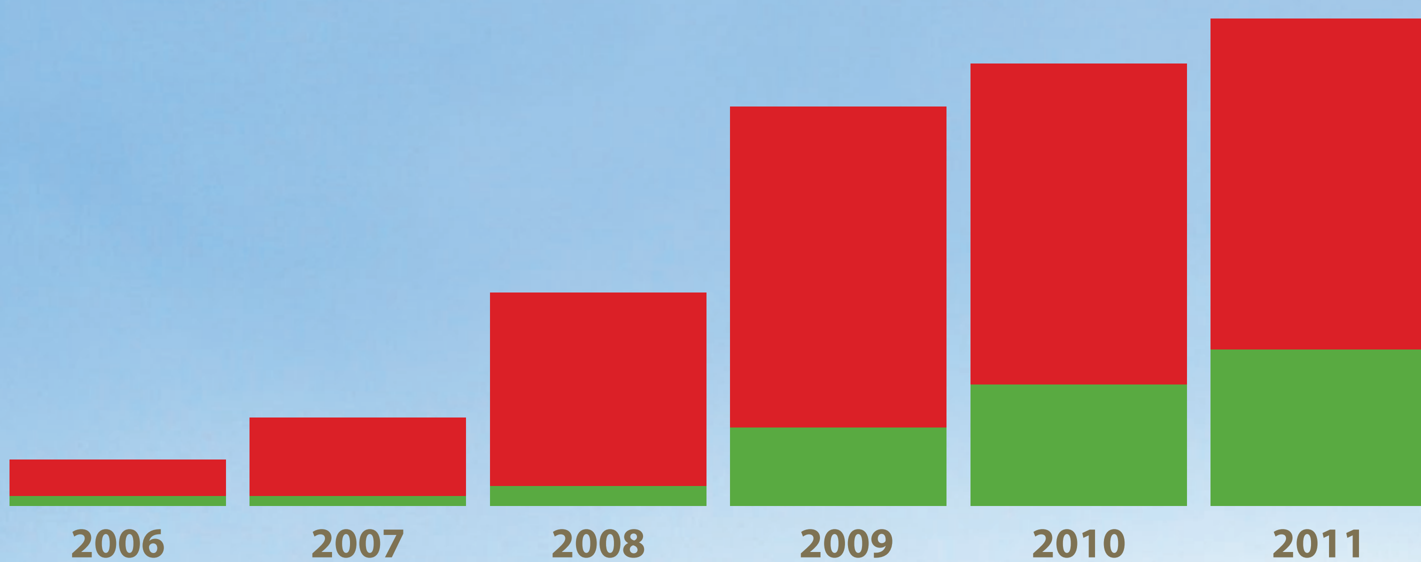
- $134.8 million of cash in hand.
- new $425 million 2024 bond issued, with longer maturities and lower cost.
- Net debt to Adjusted EBITDA ratio decreased from 3.6x to 1.7x.
- Upgraded credit rating to B+ with a stable outlook.

New Opportunities

- Argentina: low-cost, cash flow-producing acquisition in the prolific Neuquen basin with production, development, exploration and unconventional opportunities.
- Colombia: Tiple and Zamuro high-impact exploration acreage added adjacent to Llanos 34 Block.
- Long-term Latin American acquisition partnership with ONGC (India's national oil company).

2018 Outlook

- Capital investment program of $140-150 million.
- Drilling program of 40+ exploration, appraisal and development wells in Colombia, Argentina, Brazil and Chile.
- Targeted production growth of 25-30% (including Argentina) and exit production of 38,000-39,000 boepd.




Oil
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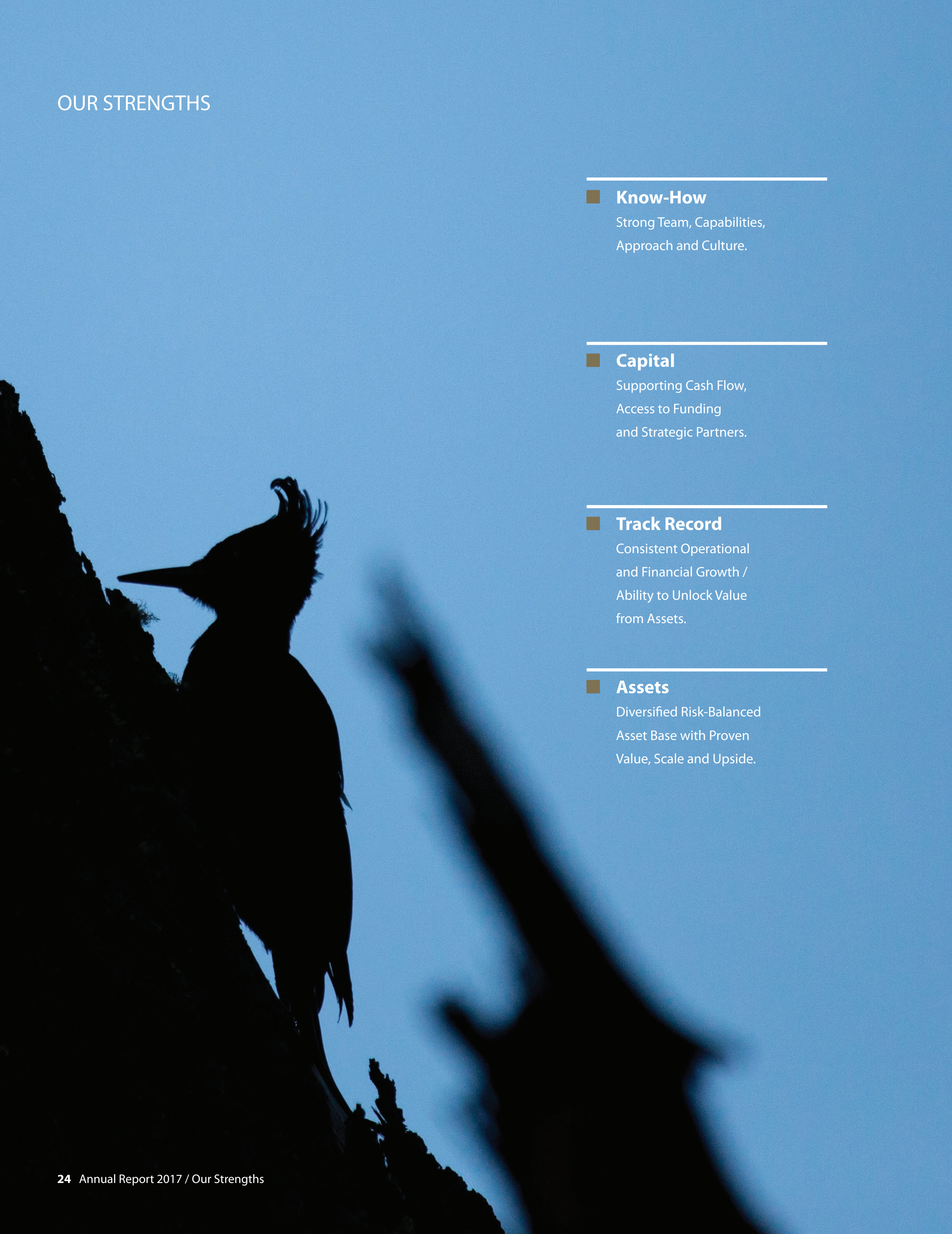
Average Daily Oil and Gas Production (Mboe/d)
2012
2013
2014
2015
2016
2017



OUR STRENGTHS

Know-How
Strong Team, Capabilities, Approach and Culture.

Capital
Supporting Cash Flow, Access to Funding and Strategic Partners.

Track Record
Consistent Operational and Financial Growth / Ability to Unlock Value from Assets.

Assets
Diversified Risk-Balanced Asset Base with Proven Value, Scale and Upside.

OUR PLATFORM

Jacana Field, Llanos 34 Block, Colombia

OUR APPROACH

GeoPark has been built around five fundamental and distinct capabilities:

Explorer

The ability, experience, methodology and creativity to find and develop oil and gas reserves in the subsurface – based on the best science, solid economics and ability to take the necessary managed risks.

Operator

The ability to execute in a timely manner and the know-how to profitably drill for, produce, treat, transport and sell our oil and gas – with the drive and persistence to find solutions, overcome obstacles, seize opportunities and achieve results.

Consolidator

The ability and initiative to assemble the right balance and portfolio of upstream assets in the right hydrocarbon basins in the right regions with the right partners and at the right price – coupled with the vision and skills to transform and improve value above ground.

Value Risk Management

The comprehensive management approach to consistently and significantly grow and build economic value per share by effective planning, balanced work programs, cost efficiency focus, secure access to capital sources, reliable communication with shareholders, and by accommodating risk among the subsurface, funding, organizational, market, partner/shareholder, and regulatory/political environments.

Culture

The commitment to build a unique performance-driven trust-based culture which values and protects our shareholders, employees, environment and communities to underpin and enhance our long-term plan for success. Our SPEED program reflects this value system and represents an integrated approach to align our business objectives with our core principles and responsibilities.

SPEED

SPEED represents GeoPark's underlying value system which provides us the leadership, confidence and foundation required for long-term success. It is our competitive advantage. And, it reflects our pride in achieving an important mission in the right way. If we are the true performer, the best place to work, the preferred partner and the cleanest operator – our future is bigger, better and more secure.

Safety

GeoPark is committed to creating a safe and healthy workplace. Simply speaking, everybody must return home everyday safe and sound.

Prosperity

GeoPark is committed to delivering significant bottom-line financial value to our shareholders. Only a financially-healthy company can continue to grow, attract needed resources and create real long-term benefits.

Employees

GeoPark is committed to creating a motivating workplace for employees. With today's shortage of capable energy professionals, the company which is able to attract, protect, retain and train the best team with the best attitude will always prevail.

Environment

GeoPark is committed to minimizing the impact of our projects on the environment. As our footprint becomes cleaner and smaller, the more areas and opportunities will be opened up for us to work in. Our long-term well-being requires us to properly fit within our surroundings.

Community Development

GeoPark is committed to being the preferred neighbor and partner by creating a mutually beneficial exchange with the local communities where we work. Unlocking local knowledge creates and supports long-term sustainable value in our projects. If our efforts enhance local goals and customs, we will be invited to do more.


GEOPARK
GEOPARK

HIGHLIGHTED SECTIONS

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 20-F

(Mark One)

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

OR

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
for the fiscal year ended December 31, 2017

OR

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

OR

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

Commission file number: 001-36298

GeoPark Limited

(Exact name of Registrant as specified in its charter)

Bermuda

(Jurisdiction of incorporation)

Nuestra Señora de los Ángeles 179 - Las Condes, Santiago, Chile

(Address of principal executive offices)

Pedro E. Aylwin Chiorrini
Director of Legal and Governance
GeoPark Limited
Nuestra Señora de los Ángeles 179 - Las Condes, Santiago, Chile
Phone: +56 (2) 2242 9600 - Fax: +56 (2) 2242 9600 ext. 201
(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Copies to:
Maurice Blanco, Esq.
Yasin Keshvargar, Esq.
Davis Polk & Wardwell LLP
450 Lexington Avenue - New York, NY 10017 | Phone: (212) 450 4000 - Fax: (212) 701 5800

Securities registered or to be registered pursuant to Section 12(b) of the Act:

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

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

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

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

Common shares: 60,596,219

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☐ Yes ☒ No

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. ☐ Yes ☒ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☐ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

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

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

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

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

☐ Item 17 ☐ Item 18

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ☐ Yes ☒ No

Table of Contents

Presentation of Financial and Other Information

Certain definitions

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

- "GeoPark Limited," "GeoPark," "we," "us," "our," the "Company" and words of a similar effect, are to GeoPark Limited (formerly GeoPark Holdings Limited), an exempted company incorporated under the laws of Bermuda, together with its consolidated subsidiaries;
- "Agencia" are to GeoPark Latin America Limited Agencia en Chile, an established branch, under the laws of Chile, of GeoPark Latin America Limited ("GeoPark Latin America"), an exempted company incorporated under the laws of Bermuda;
- "GeoPark Colombia" are prior to our internal corporate reorganization of our Colombian operations, to our subsidiary GeoPark Colombia S.A., a *sociedad anónima cerrada* incorporated under the laws of Chile and subsequent to such reorganization, to GeoPark Colombia Coöperatie U.A., a cooperative duly incorporated under the laws of the Netherlands;
- "LGI" are to LG International Corp., a company incorporated under the laws of Korea";
- "Notes due 2020" are to our 2013 issuance of US$300.0 million aggregate principal amount of 7.50% senior secured notes due 2020;
- "Notes due 2024" are to our 2017 issuance of US$425.0 million aggregate principal amount of 6.50% senior secured notes due 2024;
- "US$" and "U.S. dollar" are to the official currency of the United States of America;
- "Col$" is the official currency of Colombia;
- "Ch$" and "Chilean pesos" are to the official currency of Chile;
- "AR$" and "Argentine pesos" are to the official currency of Argentina;
- "real," "reais" and "R$" are to the official currency of Brazil;
- "ANP" are to the Brazilian National Petroleum, Natural Gas and Biofuels Agency *(Agência Nacional do Petróleo, Gás Natural e Biocombustíveis);*
- "ANH" are to the Colombian National Hydrocarbons Agency *(Agencia Nacional de Hidrocarburos);*
- "ENAP" are to the Chilean National Petroleum Company *(Empresa Nacional de Petróleo)*
- "UTA" are to Unidad Tributaria Anual;
- "economic interest" means an indirect participation interest in the net revenues from a given block based on bilateral agreements with the concessionaires; and
- "working interest" means the right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

Financial statements

Our consolidated financial statements

This annual report includes our audited consolidated financial statements as of December 31, 2017 and 2016 and for each of the years ended December 31, 2017, 2016 and 2015 (hereinafter "Consolidated Financial Statements").

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

Our Consolidated Financial Statements have been audited by Price Waterhouse & Co. S.R.L., Argentina, a member firm of PricewaterhouseCoopers Network ("PwC"), an independent registered public accounting firm, as stated in their report included elsewhere in this annual report.

Our fiscal year ends December 31. References in this annual report to a fiscal year, such as "fiscal year 2017," relate to our fiscal year ended on December 31 of that calendar year.

Non IFRS financial measures

Adjusted EBITDA

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

We define Adjusted EBITDA as profit for the period before net finance cost, income tax, depreciation, amortization and certain non-cash items such as impairment charges or impairment reversals, write-offs of unsuccessful exploration and evaluation assets, accrual of stock options and stock awards, unrealized gains in commodity risk management contracts and bargain purchase gain on acquisition of subsidiaries. Adjusted EBITDA is not a measure of profit or cash flows as determined by IFRS.

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

For a reconciliation of Adjusted EBITDA to the IFRS financial measure of profit for the year, see Note 6 to our Consolidated Financial Statements as of and for the years ended 2017, 2016 and 2015.

Oil and gas reserves and production information

DeGolyer and MacNaughton 2017 Year-end Reserves Report

The information included elsewhere in this annual report regarding estimated quantities of proved reserves in Colombia, Chile, Brazil and Peru is derived, in part, from estimates of the proved reserves as of December 31, 2017. The reserves estimates described herein are derived from the DeGolyer and MacNaughton Reserves Report (the "D&M Reserves Report"), which was prepared for us by the independent reserves engineering team of DeGolyer and MacNaughton and is included as an exhibit to this annual report. The D&M Reserves Report presents oil and gas reserves estimates located in the Fell, Campanario, Flamenco and Isla Norte Blocks in Chile, Llanos 32, Llanos 34, Yamú and La Cuerva Blocks in Colombia, BCAM-40 (Manati) in Brazil and the Morona Block in Peru.

Market share and other information

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

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

Rounding

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

Forward-looking Statements

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

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

- the volatility of oil and natural gas prices;
- operating risks, including equipment failures and the amounts and timing of revenues and expenses;
- termination of, or intervention in, concessions, rights or authorizations granted by the Chilean, Colombian, Brazilian, Peruvian and Argentine governments to us;
- uncertainties inherent in making estimates of our oil and natural gas data;
- environmental constraints on operations and environmental liabilities arising out of past or present operations;
- discovery and development of oil and natural gas reserves;
- project delays or cancellations;
- financial market conditions and the results of financing efforts;
- political, legal, regulatory, governmental, administrative and economic conditions and developments in the countries in which we operate;
- fluctuations in inflation and exchange rates in Colombia, Chile, Brazil, Peru, Argentina and in other countries in which we may operate in the future;
- availability and cost of drilling rigs, production equipment, supplies, personnel and oil field services;
- contract counterparty risk;
- projected and targeted capital expenditures and other cost commitments and revenues;
- weather and other natural phenomena;
- the impact of recent and future regulatory proceedings and changes, changes in environmental, health and safety and other laws and regulations to which our company or operations are subject, as well as changes in the application of existing laws and regulations;
- current and future litigation;
- our ability to successfully identify, integrate and complete acquisitions;
- our ability to retain key members of our senior management and key technical employees;
- competition from other similar oil and natural gas companies;
- market or business conditions and fluctuations in global and local demand for energy;
- the direct or indirect impact on our business resulting from terrorist incidents or responses to such incidents, including the effect on the availability of and premiums on insurance; and
- other factors discussed under "Item 3. Key Information—D. Risk factors" in this annual report.

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

ITEM 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

A. Directors and senior management
Not applicable.

B. Advisers
Not applicable.

C. Auditors
Not applicable.

ITEM 2. OFFER STATISTICS AND EXPECTED TIMETABLE

A. Offer statistics
Not applicable.

B. Method and expected timetable
Not applicable.

ITEM 3. KEY INFORMATION

A. Selected financial data
We have derived our selected historical balance sheet data as of December 31, 2017 and 2016 and our income statement and cash flow data for the years ended December 31, 2017, 2016 and 2015 from our Consolidated Financial Statements included elsewhere in this annual report, which have been audited by PwC. We have derived our selected balance sheet data as of December 31, 2015, 2014, and 2013 and our income statement and cash flow data for the years ended December 31, 2014 and 2013 from our Consolidated Financial Statements not included elsewhere in this annual report.

During 2015, our Management changed the presentation of the Consolidated Statement of Income by reordering the profit and loss line items, eliminating gross profit and presenting depreciation and write-off of unsuccessful efforts as separate line items. This change is intended to provide readers of our financial statements with more relevant information and a better explanation of the elements of performance. This change has been applied to comparative figures for the years 2014 and 2013 presented in this document.

We maintain our books and records in US$ and prepare our Consolidated Financial Statements in accordance with IFRS.

This financial information should be read in conjunction with "Presentation of Financial and Other Information," "Item 5. Operating and Financial Review and Prospects" and our Consolidated Financial Statements and the related notes thereto.

The selected historical financial data set forth in this section does not include any results or other financial information of our Colombian, Brazilian or Peruvian acquisitions prior to their incorporation into our financial statements.

Statement of income data

For the year ended December 31, (in thousands of US$, except per share numbers)	2017	2016	2015	2014	2013
Revenue					
Net oil sales	279,162	145,193	162,629	367,102	315,435
Net gas sales	50,960	47,477	47,061	61,632	22,918
Net revenue	**330,122**	**192,670**	**209,690**	**428,734**	**338,353**
Commodity risk management contracts	(15,448)	(2,554)	-	-	-
Production and operating costs	(98,987)	(67,235)	(86,742)	(131,419)	(111,296)
Geological and geophysical expenses	(7,694)	(10,282)	(13,831)	(13,002)	(5,292)
Administrative expenses	(42,054)	(34,170)	(37,471)	(45,867)	(44,962)
Selling expenses	(1,136)	(4,222)	(5,211)	(24,428)	(17,252)
Depreciation	(74,885)	(75,774)	(105,557)	(100,528)	(69,968)
Write-off of unsuccessful exploration efforts	(5,834)	(31,366)	(30,084)	(30,367)	(10,962)
Impairment for non-financial assets	-	5,664	(149,574)	(9,430)	–
Other operating (expense)/income	(5,088)	(1,344)	(13,711)	(1,849)	5,343
Operating profit/(loss)	**78,996**	**(28,613)**	**(232,491)**	**71,844**	**83,964**
Financial costs	(51,495)	(34,101)	(35,655)	(27,622)	(33,115)
Foreign exchange loss /gain	(2,193)	13,872	(33,474)	(23,097)	(761)
Profit (Loss) before tax	**25,308**	**(48,842)**	**(301,620)**	**21,125**	**50,088**
Income tax (expense) benefit	(43,145)	(11,804)	17,054	(5,195)	(15,154)
(Loss) Profit for the year	**(17,837)**	**(60,646)**	**(284,566)**	**15,930**	**34,934**
Non-controlling interest	6,391	(11,554)	(50,535)	7,845	12,413
(Loss) Profit attributable to owners of the Company	**(24,228)**	**(49,092)**	**(234,031)**	**8,085**	**22,521**
(Losses) Earnings per share for profit attributable to owners of the Company—Basic	**(0.40)**	**(0.82)**	**(4.05)**	**0.14**	**0.52**
(Losses) Earnings per share for profit attributable to owners of the Company—Diluted[(1)]	**(0.40)**	**(0.82)**	**(4.05)**	**0.14**	**0.48**
Weighted average common shares outstanding—Basic	**60,093,191**	**59,777,145**	**57,759,001**	**56,396,812**	**43,603,846**
Weighted average common shares outstanding—Diluted[(1)]	**60,093,191**	**59,777,145**	**57,759,001**	**58,840,412**	**46,532,049**
Common Shares outstanding at year-end	**60,596,219**	**59,940,881**	**59,535,614**	**57,790,533**	**43,861,614**

(1) See Note 19 to our Consolidated Financial Statements.

Balance sheet data

As of December 31, (In thousands of US$)	2017	2016	2015	2014	2013
Assets					
Non-current assets					
Property, plant and equipment	517,403	473,646	522,611	790,767	595,446
Prepaid taxes	3,823	2,852	1,172	1,253	11,454
Other financial assets	22,110	19,547	13,306	12,979	5,168
Deferred income tax	27,636	23,053	34,646	33,195	13,358
Prepayments and other receivables	235	241	220	349	6,361
Total non-current assets	**571,207**	**519,339**	**571,955**	**838,543**	**631,787**
Current assets					
Other financial assets	21,378	2,480	1,118	—	—
Inventories	5,738	3,515	4,264	8,532	8,122
Trade receivables	19,519	18,426	13,480	36,917	42,628
Prepayments and other receivables	7,518	7,402	11,057	13,993	35,764
Prepaid taxes	26,048	15,815	19,195	13,459	6,979
Cash at bank and in hand	134,755	73,563	82,730	127,672	121,135
Total current assets	**214,956**	**121,201**	**131,844**	**200,573**	**214,628**
Total assets	**786,163**	**640,540**	**703,799**	**1,039,116**	**846,415**
Share capital	61	60	59	58	44
Share premium	239,191	236,046	232,005	210,886	120,426
Other	(154,327)	(130,341)	(85,412)	164,613	150,371
Equity attributable to owners of the Company	84,925	105,765	146,652	375,557	270,841
Equity attributable to non-controlling interest	41,915	35,828	53,515	103,569	95,116
Total equity	**126,840**	**141,593**	**200,167**	**479,126**	**365,957**
Liabilities					
Non-current liabilities					
Borrowings	418,540	319,389	343,248	342,440	290,457
Provisions for other long-term liabilities	46,284	42,509	42,450	46,910	33,076
Trade and other payables	25,921	34,766	19,556	16,583	8,344
Deferred income tax	2,286	2,770	16,955	30,065	23,087
Total non-current liabilities	**493,031**	**399,434**	**422,209**	**435,998**	**354,964**
Current liabilities					
Borrowings	7,664	39,283	35,425	27,153	26,630
Derivative financial instrument liabilities	19,289	3,067	–	–	–
Current income tax	42,942	5,155	208	7,935	7,231
Trade and other payables	96,397	52,008	45,790	88,904	91,633
Total current liabilities	**166,292**	**99,513**	**81,423**	**123,992**	**125,494**
Total liabilities	**659,323**	**498,947**	**503,632**	**559,990**	**480,458**
Total equity and liabilities	**786,163**	**640,540**	**703,799**	**1,039,116**	**846,415**

Cash flow data

For the year ended December 31,	2017	2016	2015	2014	2013
(In thousands of US$)					
Cash provided by (used in)					
Operating activities	142,158	82,884	25,895	230,746	127,295
Investing activities	(105,604)	(39,306)	(48,842)	(344,041)	(208,500)
Financing activities	23,968	(51,136)	(18,022)	124,716	164,018
Net increase (decrease) in cash	**60,522**	**(7,558)**	**(40,969)**	**11,421**	**82,813**

Other financial data

For the year ended December 31,	2017	2016	2015	2014	2013
Adjusted EBITDA[1] (US$ thousands)	175,776	78,321	73,787	220,077	167,253
Adjusted EBITDA margin[2]	53.2%	40.6%	35.2%	51.3%	49.4%
Adjusted EBITDA per boe[3]	18.4	10.2	10.5	33.0	33.9

(1) Adjusted EBITDA is a non-IFRS financial measure. For a definition of Adjusted EBITDA and other information relating to this measure, see "Presentation of Financial and Other Information—Financial statements—Non-IFRS financial measures." For a reconciliation of Adjusted EBITDA to the IFRS financial measure of profit for the year, see Note 6 to our Consolidated Financial Statements.

(2) Adjusted EBITDA margin is defined as Adjusted EBITDA divided by net revenue.

(3) Adjusted EBITDA per boe is defined as Adjusted EBITDA divided by total boe.

Exchange rates

In Colombia, Chile, Argentina and Peru, our functional currency is the U.S. dollar. In Brazil, our functional currency is the *real*.

Our operations in Brazil accounted for 16% and 12% of our consolidated assets and 15% and 10% of our revenues for the years ended December 31, 2016 and 2017, respectively. This portion of our business is exposed to losses that may arise from currency fluctuation, as a significant amount of our revenues, operating costs, administrative expenses and taxes in Brazil are denominated in *reais*.

The *real* may depreciate or appreciate substantially against the U.S. dollar. We recorded exchange rate losses amounting to US$1.3 million for the year ended December 31, 2017, due to devaluation of the local currency in our Brazilian subsidiary. This result was mainly generated by the credit facility with Itaú BBA International plc that we incurred on March 31, 2014 to acquire Rio das Contas, which we repaid in September 2017. We recorded exchange rate gains amounting to US$14.5 million for the year ended December 31, 2016 as a result of the appreciation that occurred. See "—D. Risk factors—Risks relating to our business—Our results of operations could be materially adversely affected by fluctuations in foreign currency exchange rates."

The following tables show the selling rate for the U.S. dollar for the periods and dates indicated. The information in the "Average" column represents the average of the daily exchange rates during the periods presented. The numbers in the "Period-end" column are the quotes for the exchange rate as of the last business day of the period in question. As of April 6, 2018, the exchange rate for the purchase of the U.S. dollar as reported by the Central Bank of Brazil was R$3.3666 per U.S. dollar.

The following table presents the monthly high and low representative market rate during the months indicated.

Recent exchange rates of *Real* per US$	Period End	Average	Low	High
Month:				
October 2017	3.2769	3.1912	3.1315	3.2801
November 2017	3.2616	3.2594	3.2136	3.2920
December 2017	3.3080	3.2919	3.2322	3.3332
January 2018	3.1624	3.2106	3.1391	3.2697
February 2018	3.2449	3.2415	3.1730	3.2821
March 2018	3.3238	3.2792	3.2246	3.3380
April 2018 (through April 6, 2018)	3.3666	3.3329	3.3104	3.3666

Source: Central Bank of Brazil.

The following table presents the average R$ per U.S. dollar representative market rate for each of the five most recent years, calculated by using the average of the exchange rates on the last day of each month during the period, and the representative year-end market rate for each of the five most recent years.

Real per US$	Period/ Year End	Average	Low	High
Period:				
2013	2.3426	2.1579	1.9528	2.4457
2014	2.6562	2.3564	2.1974	2.7403
2015	3.9048	3.3876	2.5690	4.1949
2016	3.2591	3.4500	3.1193	4.1558
2017	3.3080	3.2031	3.0510	3.3807
First quarter 2018	3.3238	3.2437	3.1391	3.3380
Second quarter 2018 (through April 6, 2018)	3.3666	3.3329	3.3104	3.3666

Source: Central Bank of Brazil.

Exchange rate fluctuation may affect the US$ value of any distributions we make with respect to our common shares. See "—D. Risk factors—Risks relating to our business—Our results of operations could be materially adversely affected by fluctuations in foreign currency exchange rates."

B. Capitalization and indebtedness
Not applicable.

C. Reasons for the offer and use of proceeds
Not applicable.

D. Risk factors

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

Risks relating to our business

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

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

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

- global economic conditions;
- changes in global supply and demand for oil, natural gas and methanol;
- the actions of the Organization of the Petroleum Exporting Countries ("OPEC");
- political and economic conditions, including embargoes, in oil-producing countries or affecting other countries;
- the level of oil- and natural gas-producing activities, particularly in the Middle East, Africa, Russia, South America and the United States;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- the price of methanol;
- availability of markets for natural gas;
- weather conditions and other natural disasters;
- technological advances affecting energy production or consumption;
- domestic and foreign governmental laws and regulations, including environmental, health and safety laws and regulations;
- proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas;
- quality discounts for oil production based, among other things, on API and mercury content;
- taxes and royalties under relevant laws and the terms of our contracts;
- our ability to enter into oil and natural gas sales contracts at fixed prices;
- the level of global methanol demand and inventories and changes in the uses of methanol;
- the price and availability of alternative fuels; and
- future changes to our hedging policies.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and methanol price movements. For example, recently, oil and natural gas prices have fluctuated significantly. From January 1, 2013 to December 31, 2017, Brent spot prices ranged from a low of US$27.9 per barrel to a high of US$118.9 per barrel, Henry Hub natural gas average spot prices ranged from a low of US$1.7 per mmbtu to a high of US$6.0 per mmbtu, US Gulf methanol spot barge prices ranged from a low of US$250.0 per metric ton to a high of US$635.1 per metric ton. Furthermore, oil, natural gas and methanol prices do not necessarily fluctuate in direct relationship to each other.

For the year ended December 31, 2017, 85% of our revenues were derived from oil. Because we expect that our production mix will continue to be weighted towards oil, our financial results are more sensitive to movements in oil prices.

As of December 31, 2017, natural gas comprised 15% of our revenues. A decline in natural gas prices could negatively affect our future growth, particularly for future gas sales where we may not be able to secure or extend our current long-term contracts.

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

For example, during 2014 and 2015, we evaluated the recoverability of our fixed assets affected by the oil price decline and recorded an impairment of non-financial assets amounting to, respectively, US$9.4 million and US$149.6 million. US$5.7 million of the impairment recorded in 2015 was reversed in 2016 due to increased estimated market prices for 2017 and 2018 and improvements in cost structure. After conducting an impairment test procedure for the year ended December 31, 2017, no additional impairment of non-financial assets was recognized. See Note 36 to our Consolidated Financial Statements for details regarding oil price scenarios, discount rates considered and sensitivity analysis affecting the impairment charges.

Continuing our hedging strategy, we entered into derivative financial instruments to manage exposure to oil price risk. These derivatives were zero-premium collars or zero premium three way hedges (put, spread and call) and were placed with major financial institutions and commodity traders. We 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 protecting us from potential non-performance risk by our counterparties. See Note 8 to our Consolidated Financial Statements for details regarding Commodity Risk Management Contracts.

The oil price crisis has impacted our operations and corporate strategy.

We face limitations on our ability to increase prices or improve margins on the oil and natural gas that we sell. As a consequence of the oil price crisis which started in the second half of 2014 (WTI and Brent, the main international oil price markers, fell by more than 60% between August 2014 and March 2016), the Company took decisive measures to ensure its ability to both maximize ongoing projects and to preserve its cash.

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

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

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

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

Production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Accordingly, our current proved reserves will decline as these reserves are produced. As of December 31, 2017, our reserves-to-production (or reserve life) ratio for net proved reserves in Colombia, Chile, Brazil and Peru was 9.5 years. According to estimates, if on January 1, 2018 we ceased all drilling and development activities, including recompletions, refracs and workovers, our proved developed producing reserves base in Colombia, Chile, Brazil and Peru would decline 35% during the first year.

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

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

In Colombia, for the year ended December 31, 2017, we made 100% of our oil sales from operated blocks to C.I. Trafigura Petroleum Colombia S.A.S., a leading commodity trading and logistics company ("Trafigura"), representing 79% of our consolidated revenues for the same period. Sales for the year ended December 31, 2017 were made mostly under long-term agreements. For 2018, all of the oil production from the blocks we operate in Colombia is committed to Trafigura under the Trafigura Sales Agreement.

In Chile, 100% of our crude oil and condensate sales are made to ENAP. For the year ended December 31, 2017, sales to ENAP represented 5% of our total revenues. ENAP imports the majority of the oil it refines and partially supplements those imports with volumes supplied locally by its own operated fields and those operated by us. On April 21, 2017, we renewed our sales agreement with ENAP. As part of this agreement, ENAP has committed to purchase our oil production in the Fell Block in the amounts that we produce, subject to the limitation of available storage capacity at the Gregorio Terminal. The sales agreement provides us with the option to interrupt sales to ENAP periodically if conditions in the export markets allow for more competitive price levels. While the agreement renews automatically on an annual basis, we typically make an annual revision jointly with ENAP. In addition, for the year ended December 31, 2017, almost all of our natural gas sales in Chile were made to Methanex Chile SpA., the Chilean subsidiary of the Methanex Corporation ("Methanex"), a leading global methanol producer, under a long-term contract (the "Methanex Gas Supply Agreement") which expired on April 30, 2017. In March 2017, we executed a new gas supply agreement with Methanex effective from May 1, 2017 to December 31, 2026. Sales to Methanex represented 5% of our consolidated revenues for the year ended December 31, 2017.

In Brazil, all of our gas and condensate produced in the Manati Field is sold to Petróleo Brasileiro S.A. ("Petrobras"), the operator of the Manati Field, pursuant to a long-term gas off-take contract. See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Brazil—Petrobras Natural Gas Purchase Agreement."

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

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

Although a majority of our net revenues is denominated in US$, unfavorable fluctuations in foreign currency exchange rates for certain of our expenses in Colombia, Chile, Brazil, Peru and Argentina could have a material adverse effect on our results of operations. A portion of the cost reductions that we achieved in 2015 and 2016 (as compared to 2014) were related to the depreciation of local currencies, including mainly the Col$, the Ch$ and the Brazilian real. An appreciation of local currencies can increase our costs and negatively impact our results from operations.

Furthermore, we have not entered, into derivative transactions to hedge the effect of changes in the exchange rate of local currencies to the US$. Because our Consolidated Financial Statements are presented in US$, we must translate revenues, expenses and income, as well as assets and liabilities, into US$ at exchange rates in effect during or at the end of each reporting period.

Through our Brazilian operations, we are exposed to fluctuations in the real against the US$, as our Brazilian revenues and expenses are mostly denominated in reais. In the past, the Brazilian Central Bank has occasionally intervened to control unstable movements in foreign exchange rates. We cannot predict whether the Brazilian Central Bank or the Brazilian government will continue to permit the real to float freely or will intervene in the exchange rate market through the return of a currency band system or otherwise. Furthermore, Brazilian law provides that, whenever there is a serious imbalance in Brazil's balance of payments or there are reasons to foresee a serious imbalance, temporary restrictions may be imposed on remittances of foreign capital abroad. We cannot assure you that such measures will not be taken by the Brazilian government in the future. The real has experienced frequent and substantial variations in relation to the US$ and other foreign currencies, which could materially and adversely affect the growth of the Brazilian economy and our business, financial condition and results of operations.

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

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

Furthermore, the marketability of any oil and natural gas production from our projects may be affected by numerous factors beyond our control.

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

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

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

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

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

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

Because the oil and natural gas industry is capital intensive, we expect to make substantial capital expenditures in our business and operations for the exploration and production of oil and natural gas reserves. See "Item 4. Information on the Company –B. Business Overview—2018 Strategy and Outlook." We incurred capital expenditures of US$106 million and US$39 million during the years ended December 31, 2017 and 2016, respectively. See "Item 5. Operating and Financial Review and Prospects—A. Operating Results—Factors Affecting our Results of Operations—Discovery and exploitation of reserves."

The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other equipment and services, and regulatory, technological and competitive developments. In response to changes in commodity prices, we may increase or decrease our actual capital expenditures. We intend to finance our future capital expenditures through cash generated by our operations and potential future financing arrangements. However, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets.

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

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

Oil and gas exploration and production is speculative and involves a high degree of risk and hazards. In particular, our operations may be disrupted by risks and hazards that are beyond our control and that are common among oil and gas companies, including environmental hazards, blowouts, industrial accidents, occupational safety and health hazards, technical failures, labor disputes, community protests or blockades, unusual or unexpected geological formations, flooding, earthquakes and extended interruptions due to weather conditions, explosions and other accidents.

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

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

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

- shortages of equipment, materials and labor;
- fluctuations in the prices of construction materials;
- delays in delivery of equipment and materials;
- labor disputes;
- political events;
- title problems;
- obtaining easements and rights of way;
- blockades or embargoes;
- litigation;
- compliance with governmental laws and regulations, including environmental, health and safety laws and regulations;
- adverse weather conditions;
- unanticipated increases in costs;
- natural disasters;
- accidents;
- transportation;
- unforeseen engineering and drilling complications;
- environmental or geological uncertainties; and
- other unforeseen circumstances.

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

For example, in 2017, the drilling and completion cost for the exploratory well Río Grande Oeste x-1 in our CN-V Block in Argentina was originally estimated at US$4.2 million, but the actual cost was US$5.5 million, mainly due to mechanical issues related to failures with an electric submersible pump, as well as testing of additional formations which had not been budgeted.

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

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

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

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

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

Our oil and gas reserves estimates in Colombia, Chile, Brazil, and Peru as of December 31, 2017 are based on the D&M Reserves Report. Although classified as "proved reserves," the reserves estimates set forth in the D&M Reserves Reports are based on certain assumptions that may prove inaccurate. DeGolyer and MacNaughton's primary economic assumptions in estimates included oil and gas sales prices determined according to SEC guidelines, future expenditures and other economic assumptions (including interests, royalties and taxes) as provided by us.

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

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

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

In Colombia, producers of crude oil have historically suffered from tanker transportation logistics issues and limited storage capacity, which cause delays in delivery and transfer of title of crude oil. Such capacity issues in Colombia may require us to transport crude from our Colombian operations via truck, which may increase the costs of those operations. Road infrastructure is limited in certain areas in which we operate, and certain communities have used and may continue to use road blockages, which can sometimes interfere with our operations in these areas. For example, in 2017, the main delivery point for the Colombian production was Oleoducto de Los Llanos "ODL." Between November 8, 2017 and November 11, 2017, a disruption of the operation of this pipeline occurred and affected its capacity to transport any volume of crude oil. Our Colombian production was impacted by approximately 5,800 bbls during that period. Although we were able to increase the delivery volumes the following days to mitigate the impact, we cannot assure you we would be able to do so in the future.

In Chile, we transport the crude oil we produce in the Fell Block by truck to ENAP's processing, storage and selling facilities at the Gregorio Refinery. As of the date of this annual report, ENAP purchases all of the crude oil we produce in Chile. We rely upon the continued good condition, maintenance and accessibility of the roads we use to deliver the crude oil we produce. If the condition of these roads were to deteriorate or if they were to become inaccessible for any period of time, this could delay delivery of crude oil in Chile and materially harm our business.

In the Fell Block, we depend on ENAP-owned gas pipelines to deliver the gas we produce to Methanex, the sole purchaser of the gas we produce. If ENAP's pipelines were unavailable, this could have a materially adverse effect on our ability to deliver and sell our product to Methanex, which could have a material adverse effect on our gas sales. In addition, gas production in some areas in the Tierra del Fuego Blocks and the Tranquilo Block could require us to build a new network of gas pipelines in order for us to be able to deliver our product to market, which could require us to make significant capital investments.

While Brazil has a well-developed network of hydrocarbon pipelines, storage and loading facilities, we may not be able to access these facilities when needed. Pipeline facilities in Brazil are often full and seasonal capacity restrictions may occur, particularly in natural gas pipelines. Our failure to secure transportation or access to pipelines or other facilities once we commence operations in the concessions we were awarded in Brazil on acceptable terms or on a timely basis could materially harm our business.

In Peru, future production in the Morona Block is expected to be transported through the existing North Peruvian Pipeline, which was out of service in 2017 due to technical issues. Though the Peruvian government is implementing a program to maintain the pipeline, future technical issues, other general infrastructure problems or social unrest affecting pipeline operation may adversely affect the recoverability of our future investments, our future production or revenues related to the Morona Block.

In addition, as the Morona Block is located in a remote area of the tropical rainforest, the development of the project involves that significant infrastructure has to be built, as processing facilities, storages tanks and an approximately 97 km pipeline from the site to the North Peruvian Pipeline. Also, as there are no roads available in the surrounding area, logistics will be performed by helicopters or barges during specific seasons of the year. These issues may lead us to incur significant costs or investments that may not be recoverable through our commercial activities in the Morona Block.

Our use of seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas.

Even when properly used and interpreted, seismic data and visualization techniques are tools only used to assist geoscientists in identifying subsurface structures as well as eventual hydrocarbon indicators, and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of seismic and other advanced technologies requires significant expenditures and we could incur losses as a result of these expenditures. Because of these uncertainties associated with our use of seismic data, some of our drilling activities may not be successful or economically viable, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline, which could have a material adverse effect on us.

Through our Brazilian operations, we face operational risks relating to offshore drilling.

Our operations in the BCAM-40 Concession in Brazil may include shallow-offshore drilling activity in two areas in the Camamu-Almada Basin, which we expect will continue to be operated by Petrobras.

Offshore operations are subject to a variety of operating risks and laws and regulations, including among other things, with respect to environmental, health and safety matters, specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities, compliance costs, fines or penalties that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties. For example, the Manati Field has been subject to administrative infraction notices, which have resulted in fines against Petrobras in an aggregate amount of approximately US$12 million, all of which are pending a final decision of the Brazilian Institute for the Environment and Natural Renewable Resources (Instituto Brasileiro do Meio-Ambiente e dos Recursos Naturais Renováveis). Although the administrative fines were filed against Petrobras, as a party to the concession agreement governing the Manati Field, we may be liable up to our participation interest of 10%.

Additionally, offshore drilling generally requires more time and more advanced drilling technologies, involving a higher-risk of technological failure and usually higher drilling costs. Offshore projects often lack proximity to existing oilfield service infrastructure, necessitating significant capital investment in flow line infrastructure before we can market the associated oil or gas of a commercial discovery, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some offshore reserve discoveries may never be produced economically.

Further, because we are not the operator of our offshore fields, all of these risks may be heightened since they are outside of our control. We have a 10% interest in the Manati Field which limits our operating flexibility in such offshore fields. See "—We are not, and may not be in the future, the sole owner or operator of all of our licensed areas and do not, and may not in the future, hold all of the working interests in certain of our licensed areas. Therefore, we may not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and, to an extent, any non-wholly-owned, assets."

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

Access to the sites where we operate requires agreements (including, for example, assessments, rights of way and access authorizations) with landowners and local communities. If we are unable to negotiate agreements with landowners, we may have to go to court to obtain access to the sites of our operations, which may delay the progress of our operations at such sites. In Chile and in Argentina, for example, we have negotiated the necessary agreements for many of our current operations in the Magallanes Basin and CN-V Block in Mendoza, respectively. In Brazil, in the event that social unrest continues or intensifies, this may lead to delays or damage relating to our ability to operate the assets we have acquired or may acquire in our Brazil Acquisitions.

In Colombia, although we have agreements with many landowners and are in negotiations with others, we expect our costs to increase following current and future negotiations regarding access to our blocks, as the economic expectations of landowners have generally increased, which may delay access to existing or future sites. In addition, the expectations and demands of local communities on oil and gas companies operating in Colombia may also increase. As a result, local communities have demanded that oil and gas companies invest in remediating and improving public access roads, compensate them for any damages related to use of such roads and, more generally, invest in infrastructure that was previously paid for with public funds. Due to these circumstances, oil and gas companies in Colombia, including us, are now dealing with increasing difficulties resulting from instances of social unrest, temporary road blockages and conflicts with landowners.

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

In Peru, the Morona Block is located in land inhabited by native communities. Though we have already signed certain agreements with native communities authorizing the execution of the Environmental Impact Assessment for the Morona Project, similar projects in the Peruvian rainforest have faced significant social conflicts and work delays due to community claims. Social conflicts or community claims could adversely affect the recoverability of our future investments, our future production and revenues related to the Morona Block.

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

In order to protect our exploration and production rights in our license areas, we must meet various drilling and declaration requirements. In general, unless we make and declare discoveries within certain time periods specified in our various special operation contracts (Contratos Especiales de Operación para la Exploración y Explotación de Yacimientos de Hidrocarburo; hereinafter "CEOP"), E&P Contracts and concession agreements, our interests in the undeveloped parts of our license areas may lapse. Should the prospects we have identified under these contracts and agreements yield discoveries, we may face delays in drilling these prospects or be required to relinquish these prospects. The costs to maintain or operate the CEOPs, E&P Contracts and concession agreements over such areas may fluctuate and may increase significantly, and we may not be able to meet our commitments under such contracts and agreements on commercially reasonable terms or at all, which may force us to forfeit our interests in such areas. For example, in 2016, after fulfilling the committed exploratory commitments, five exploratory blocks were relinquished to the ANP. See "Item 4. Information on the Company—B. Business Overview—Our operations—Operations in Brazil."

In Peru, the rights to explore and produce hydrocarbons are granted through a license contract signed with Perupetro. The scope and schedule of such development will depend on us and Petroperu. The license contract could be terminated by Perupetro if the development obligations included in such agreement are not fulfilled. In addition, there is also an exploratory commitment consisting of the drilling of one exploratory well every two and a half years. Failure to fulfill the exploratory commitment will lead to acreage relinquishment materially affecting the project. Moreover, we have entered into a Joint Investment Agreement with Petroperu by which, subject to the economic and technical feasibility of the Morona Project, we are obliged to bear 100% of capital cost required to carry out long test to existing well Situche Central 3X, and if we decide to continue with the project after that, to the existing well Situche Central 2X. In addition, we are required to cover any capital or operational expenditures associated with the project until December 31, 2020. We expect these expenditures to be substantially reimbursed by Petroperu from revenues associated with future sales. Failure to fulfill such obligations will result in the loss of our participating interest in the License Contract of the Morona Block, and subject us to possible damage claims from Petroperu.

For additional details regarding the status of our operations with respect to our various special contracts and concession agreements, see "Item 4. Information on the Company—B. Business Overview—Our operations."

A significant amount of our reserves or production have been derived from our operations in certain blocks, including the Llanos 34 Block in Colombia, the Fell Block in Chile, the BCAM-40 Concession in Brazil and the Morona Block in Peru.

For the year ended December 31, 2017, the Llanos 34 Block contained 66% of our net proved reserves and generated 75% of our production, the Fell Block contained 8% of our net proved reserves and generated 10% of our total production, the BCAM-40 Concession contained 4% of our net proved reserves and generated 11% of our production and the Morona Block contained 20% of our net proved reserves. While our continuing expansion with new exploratory blocks incorporated in our portfolio mean that the above mentioned blocks may be expected to be a less significant component of our overall business, we cannot be sure that we will be able to continue diversifying our reserves and production. Resulting from these, any government intervention, impairment or disruption of our production due to factors outside of our control or any other material adverse event in our operations in such blocks would have a material adverse effect on our business, financial condition and results of operations.

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

Under certain CEOPs, E&P Contracts and concession agreements to which we are or may in the future become parties, we are or may become subject to guarantees to perform our commitments and/or to make payment for other obligations, and we may not be able to obtain financing for all such obligations as they arise. If such obligations are not complied with when due, in addition to any other remedies that may be available to other parties, this could result in cancelation of our CEOPs, E&P Contracts and concession agreements or dilution or forfeiture of interests held by us. As of December 31, 2017, the aggregate outstanding amount of this potential liability for guarantees was US$28.4 million, mainly related to capital commitments in Isla Norte, Campanario and Flamenco Blocks in Chile, rounds 11, 12 and 13 concessions in Brazil, the Morona Block in Peru and the Llanos 32, VIM-3, and Llanos 34 Blocks in Colombia. See "Item 4. Information on the Company—B. Business Overview—Our operations" and Note 32(b) to our Consolidated Financial Statements.

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

In Colombia, our E&P Contracts may be subject to early termination for a breach by the parties, a default declaration, application of any of the contracts' unilateral termination clauses or pursuant to termination clauses mandated by Colombian law. Anticipated termination declared by the ANH results in the immediate enforcement of monetary guaranties against us and may result in an action for damages by the ANH and/or a restriction on our ability to engage in contracts with the Colombian government during a certain period of time. See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Colombia—E&P Contracts."

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

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

In Peru, License Contracts for hydrocarbon exploitation are in force and will remain in effect for 30 years. This term is non-renewable. With regard to the Morona Block, approximately one-third of the contract term has already elapsed, and twenty years remain. Nevertheless, since May 14, 2013, the License Contract related to the Morona Block is under force majeure. During a force majeure period contract terms are suspended (including the term time) as long as the party to the contract is fulfilling certain obligations related to obtaining environmental permits, as is currently the case with the Morona Block. The term of the agreement will be extended by the same amount of time it has been suspended by a force majeure event. The concession year expiration is related to approval of environmental impact assessment (EIA) study for project development. The expiration of the License Contract will occur twenty years after EIA approval. The License Contract is also subject to early termination in case of our breach of contractual obligations. In such an event, all the existing facilities and wells located in the block will be transferred, without charge, to Perupetro, and we will have to carry out abandonment plans for remediation and restoration of any polluted area in the block and for de-commission the facilities that are no longer required for the block's operations.

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

We may not be able to meet delivery requirements under the crude sale agreements in Colombia.

We historically sold to several customers in Colombia, including sales made through wellhead or pipeline. For 2018, we expect to sell almost all of our Colombian production under long-term agreements with Trafigura. The Trafigura offtake contract began in March 2016 and expires in December 2018.

The amended Trafigura Agreement sets the current volumes to be delivered to Trafigura to 12,000 bopd until December 2018. Nonperformance of our obligations of delivery to Trafigura in terms, amounts and quality of the crude may lead us to pay ship-or-pay commitments in the ODL Pipeline for the transport, dilution and download of crude as well as compensation for other costs. Additionally, such nonperformance may lead to early termination of the crude sales agreement as well as the immediate repayment of any amounts outstanding under the prepayment agreement of up to US$100 million, as well as compensation for other damages. As of December 31, 2017, the outstanding balance was US$10 million, relating to the amount we agreed to prepay Trafigura.

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

For the year ended December 31, 2017, almost all of our natural gas sales in Chile were made to Methanex under a long-term contract, the Methanex Gas Supply Agreement, which expires on December 31, 2026. Under the agreement, Methanex committed to purchase up to 400,000 SCM/d of gas produced by us. For 2018, the commitment was reduced to 315,000 SCM/d, due to the decline in the gas production. We also hold an option to deliver up to 15% above this volume. Sales to Methanex represented approximately 5% of our consolidated revenues for the year ended December 31, 2017. Methanex also buys gas from ENAP and a consortium that Methanex has formed with ENAP. If Methanex were to decrease or cease its purchase of gas from us, this would have a material adverse effect on our revenues derived from the sale of gas.

Methanex has two methanol producing facilities at its Cabo Negro production facility, near the city of Punta Arenas in southern Chile. Methanex relies on local suppliers of natural gas, including ENAP, for its operations. We alone cannot supply Methanex with all the natural gas it requires for its operations.

In the past, the Methanex plant was idled due to an anticipated insufficient supply of natural gas. The supply of natural gas decreased during the winter months of 2015 due to the increase in seasonal gas demand from the city of Punta Arenas, to which gas producers, including us, gave priority by delivering gas to the city through Methanex which re-sold our gas to ENAP. In May 2017, the Methanex plant shut down because of a technical failure which affected our natural gas production and sales for 20 days. See "Item 4. Information on the Company—B. Business Overview—Marketing and delivery commitments—Chile."

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

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

As of December 31, 2017, we are not the operator of 21% or sole owner of 38% of the blocks included in our portfolio. See "Item 4. Information on the Company—B. Business Overview—Operations in Colombia, Operations in Chile, Operations in Brazil, Operations in Peru and Operations in Argentina."

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

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

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

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

LGI, our strategic partner in Chile and Colombia, may not consent to our taking certain actions or may eventually decide to sell its interest in our Chilean and Colombian operations to a third party.

We have a strategic partnership with LGI, which has a 20% equity interest in GeoPark Chile S.A., (a sociedad anónima cerrada incorporated under the laws of Chile; hereinafter "GeoPark Chile"), a 14% direct equity interest in GeoPark TdF S.A. ("GeoPark TdF") (31.2% taking into account direct and indirect participation through GeoPark Chile) and a 20% equity interest in GeoPark Colombia SAS, through its equity interest in GeoPark Colombia Coöperatie. Our shareholders' agreements with LGI in each of Chile and Colombia provides that we have a right of first offer if LGI decides to sell any of its interest in GeoPark Chile or GeoPark Colombia

Coöperatie. There can be no assurance, however, that we will have the funds to purchase LGI's interest in Chile and/or Colombia and that LGI will not decide to sell its shares to a third party whose interests may not be aligned with ours.

In addition, our shareholders' agreements with LGI in Chile and Colombia contain provisions that require GeoPark Chile and GeoPark Colombia Coöperatie, the sole shareholder of GeoPark Colombia SAS, to obtain LGI's consent before undertaking certain actions. For example, under the terms of the shareholders' agreement with LGI in Colombia, LGI must approve GeoPark Colombia's annual budget and work programs and mechanisms for funding any such budget or program, the entering into any borrowings other than those provided in an approved budget or incurred in the ordinary course of business to finance working capital needs, the granting of any guarantee or indemnity to secure liabilities of parties other than those of our Colombian subsidiary and disposing of any material assets other than those provided for in an approved budget and work program.

Additionally, pursuant to our agreement with LGI in Colombia, we and LGI have agreed to vote our common shares or otherwise cause GeoPark Colombia Coöperatie to declare dividends only after allowing for retentions of cash for approved work programs and budgets capital adequacy requirements, working capital requirements, banking covenants associated with any loan entered into by GeoPark Colombia Coöperatie and GeoPark Colombia SAS and operational requirements. Our inability or failure to obtain LGI's consent or a delay by LGI in granting its consent may restrict or delay the ability of GeoPark Chile, GeoPark TdF or GeoPark Colombia to take certain actions, which may have an adverse effect on our operations in such countries and on our business, financial condition and results of operations.

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

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

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

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

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

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

For example, we recently acquired a 100% working interest and operatorship of the Aguada Baguales, El Porvenir and Puesto Touquet blocks in Argentina. Our estimates regarding the oil and gas production capabilities of these blocks could prove to be incorrect. In addition, development and operating costs may be greater than we expect, and we may not be able to successfully integrate these blocks. If we fail to realize the benefits we anticipate from this or other acquisitions, our results of operations may be adversely affected.

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

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

The PN-T-597 Concession Agreement in Brazil may not close.

In Brazil, GeoPark Brasil is a party to a class action filed by the Federal Prosecutor's Office regarding a concession agreement of exploratory Block PN-T-597, which the ANP initially awarded GeoPark Brasil in the 12th oil and gas bidding round held in November 2013. The Brazilian Federal Court issued an injunction against the ANP and GeoPark Brasil in December 2013 that prohibited GeoPark Brasil's execution of the concession agreement until the ANP conducted studies on whether drilling for unconventional resources would contaminate the dams and aquifers in the region. On July 17, 2015, GeoPark Brasil, at the instruction of the ANP, signed the concession agreement, which included a clause prohibiting GeoPark Brasil from conducting unconventional exploration activity in the area. Despite the clause containing the prohibition, the judge in the case concluded that the concession agreement should not be executed. Thus, GeoPark Brasil requested that the ANP comply with the decision and annul the concession agreement, which the ANP's Board did on October 9, 2015. The annulment reverted the status of all parties to the status quo ante, which maintains GeoPark Brasil's right to the block.

There is no assurance that we will be able to enter into a concession agreement in the PN-T-597 Block that would be favorable to our exploration goals. See "Item 8—Financial Information—A. Consolidated statements and other financial information—Legal proceedings."

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

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. For the year ended December 31, 2017, we have based the estimated discounted future net revenues from our proved reserves on the 12 month unweighted arithmetic average of the first-day-of-the-month price for the preceding 12 months. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

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

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

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

As of December 31, 2017, approximately 39% of our net proved reserves are developed. Development of our undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Additionally, delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the standardized measure value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves, and may result in some projects becoming uneconomic, causing the quantities associated with these uneconomic projects to no longer be classified as reserves. This was due to the uneconomic status of the reserves, given the proximity to the end of the concessions for these blocks, which does not allow for future capital investment in the blocks. There can be no assurance that we will not experience similar delays or increases in costs to drill and develop our reserves in the future, which could result in further reclassifications of our reserves.

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

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

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

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

We may not have the capital to develop our unconventional oil and gas resources.

We have identified opportunities for analyzing the potential of unconventional oil and gas resources in some of our blocks and concessions. Our ability to develop this potential depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services and personnel and drilling results. In addition, as we have no previous experience in drilling and exploiting unconventional oil and gas resources, the drilling and exploitation of such unconventional oil and gas resources depends on our ability to acquire the necessary technology, to hire personnel and other support needed for extraction or to obtain financing and venture partners to develop such activities. Because of these uncertainties, we cannot give any assurance as to the timing of these activities, or that they will ultimately result in the realization of proved reserves or meet our expectations for success.

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

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

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

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

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

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

We have not been and may not be at all times in complete compliance with environmental permits that we are required to obtain for our operations and the environmental and health and safety laws and regulations to which we are subject. If we fail to comply with such requirements, we could be fined or otherwise sanctioned by regulators, including through the revocation of our permits or the suspension or termination of our operations. If we fail to obtain, maintain or renew permits in a timely manner or at all, our operations could be adversely affected, impeded, or terminated, which could have a material adverse effect on our business, financial condition or results of operations. Some environmental licenses related to operation of the Manati Field production system and natural gas pipeline have expired. However, the operator submitted in a timely manner a request for renewal of those licenses and as such this operation is not in default as long as the regulator does not state its final position on the renewal.

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

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

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

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

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

Hydraulic fracturing of unconventional oil and gas resources is a process that involves injecting water, sand, and small volumes of chemicals into the wellbore to fracture the hydrocarbon-bearing rock thousands of feet below the surface to facilitate a higher flow of hydrocarbons into the wellbore. We are contemplating such use of hydraulic fracturing in the production of oil and natural gas from certain reservoirs, especially shale formations. We currently are not aware of any proposals in Colombia, Chile, Brazil, Argentina or Peru to regulate hydraulic fracturing beyond the regulations already in place. However, various initiatives in other countries with substantial shale gas resources have been or may be proposed or implemented to, among other things, regulate hydraulic fracturing practices, limit water withdrawals and water use, require disclosure of fracturing fluid constituents, restrict which additives may be used, or implement temporary or permanent bans on hydraulic fracturing. If any of the countries in which we operate adopts similar laws or regulations, which is something we cannot predict right now, such adoption could significantly increase the cost of, impede or cause delays in the implementation of any plans to use hydraulic fracturing for unconventional oil and gas resources.

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

As of December 31, 2017, we had US$426.2 million of total indebtedness outstanding on a consolidated basis, consisting primarily of our $425.0 million Notes due 2024, which we issued in September 2017. Substantially all of our debt is secured. As of December 31, 2017, our annual debt service obligation was US$30.0 million, which mainly consists of the interest payments under the now repaid Notes due 2020, the now repaid credit facility with Itaú BBA International plc and the Notes due 2024. See "Item 5. Operating and Financial Review and Prospects—B. Liquidity and Capital Resources—Indebtedness." Using cash provided by the offering of the Notes due 2024, we (i) repurchased US$284.0 million aggregate principal amount of the outstanding Notes due 2020 in September 2017 and redeemed the remaining US$16.0 million aggregate principal amount outstanding in October 2017 and (ii) repaid the credit facility with Itaú BBA International plc in September 2017. We are also restricted from entering into financial arrangements in some circumstances such as in Colombia where LGI must approve GeoPark Colombia's financial arrangements. See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Agreements with LGI—LGI Colombia Agreements" for more information.

Our indebtedness could:

- limit our capacity to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt instruments, including restrictive covenants and borrowing conditions, could result in an event of default under the agreements governing our indebtedness;
- require us to dedicate a substantial portion of our cash flow from operations to the payments on our indebtedness, thereby reducing the availability of our cash flow to fund acquisitions, working capital, capital expenditures and other

general corporate purposes;

- place us at a competitive disadvantage compared to certain of our competitors that have less debt;
- limit our ability to borrow additional funds;
- in the case of our secured indebtedness, lose assets securing such indebtedness upon the exercise of security interests in connection with a default;
- make us more vulnerable to downturns in our business or the economy; and
- limit our flexibility in planning for, or reacting to, changes in our operations or business and the industry in which we operate.

The indenture governing our Notes due 2024 includes covenants restricting dividend payments. For a description, see "Item 5. Operating and Financial Review and Prospects—B. Liquidity and Capital Resources—Indebtedness—Notes due 2024."

As a result of these restrictive covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs. We have in the past been unable to meet incurrence tests under the indenture governing our now repaid Notes due 2020, which limited our ability to incur indebtedness. Failure to comply with the restrictive covenants included in our Notes due 2024 would not trigger an event of default.

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

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

Our business processes depend on the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure in response to our changing needs. It is critical to our business that our facilities and infrastructure remain secure. Although we have implemented internal control procedures to assure the security of our data, we cannot guarantee that these measures will be sufficient for this purpose. The ability of the information technology function to support our business in the event of a security breach or a disaster such as fire or flood and our ability to recover key systems and information from unexpected interruptions cannot be fully tested and there is a risk that, if such an event actually occurs, we may not be able to address immediately the repercussions of a breach. In the event of a breach, key information and systems may be unavailable for a number of days leading to an inability to conduct our business or perform some business processes in a timely manner. We have implemented strategies to mitigate the impact from these types of events.

In addition, the oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. For example, software programs are used to interpret seismic data, manage drilling rigs, conduct reservoir modeling and reserves estimation, and to process and record financial and operating data. We depend on digital technology, including information systems and related infrastructure as well as cloud application and services, to process and record financial and operating data, communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. Our business partners, including vendors, service providers, co-venturers, purchasers of our production, and financial institutions, are also dependent on digital technology. As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased.

A cyber-attack could include gaining unauthorized access to digital systems for purposes of misappropriating assets or sensitive information, corrupting data, or causing operational disruption, or result in denial-of-service on websites. Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. Our employees have been and will continue to be targeted by parties using fraudulent "spam" and "phishing" emails to misappropriate information or to introduce viruses or other malware through "trojan horse" programs to our computers. These emails appear to be legitimate emails sent by us but direct recipients to fake websites operated by the sender of the email or request that the recipient send a password or other confidential information through email or download malware. Despite our efforts to mitigate "spoof" and "phishing" emails through education, "spoof" and "phishing" activities remain a serious problem that may damage our information technology infrastructure.

Certain cyber incidents, such as surveillance, may remain undetected for an extended period. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations. Although to date we have not experienced any significant cyber-attacks, there can be no assurance that we will not be the target of cyber-attacks in the future or suffer such losses related to any cyber-incident. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks relating to the countries in which we operate

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

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

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

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

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

In addition, our operations in these areas increase our exposure to risks of guerilla activities, social unrest, local economic conditions, political disruption, civil disturbance, community protests or blockades, expropriation, piracy, tribal conflicts and governmental policies that may: disrupt our operations; require us to incur greater costs for security; restrict the movement of funds or limit repatriation of profits; lead to U.S. government or international sanctions; limit access to markets for periods of time; or influence the market's perception of the risk associated with investments in these countries. Some countries in the geographic areas where we operate have experienced, and may experience in the future, political instability, and losses caused by these disruptions may not be covered by insurance. Consequently, our exploration, development and production activities may be substantially affected by factors which could have a material adverse effect on our results of operations and financial condition. We cannot guarantee that current programs and policies that apply to the oil and gas industry will remain in effect.

Our operations may also be adversely affected by laws and policies of the jurisdictions, including Bermuda, Colombia, Chile, Brazil, Peru, Argentina, Spain, the United Kingdom, the Netherlands and other jurisdictions in which we do business, that affect foreign trade and taxation, and by uncertainties in the application of, possible changes to (or to the application of) tax laws in these jurisdictions. For example, in 2016 the Colombian government introduced tax reforms with provisions that are effective January 1, 2017. See Note 16 to our Consolidated Financial Statements. With regards to Chile, although our CEOPs have protection against tax changes through invariability tax clauses, potential issues may arise on certain aspects not clearly defined in current or future tax reforms.

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

The political and economic uncertainty in Brazil along with the ongoing "Lava Jato" investigations regarding corruption at Petrobras may hinder the growth of the Brazilian economy and could have an adverse effect on our business.

Our Brazilian operations represent 10% of our revenues as of December 31, 2017. The Brazilian economy has been experiencing a slowdown. Inflation, unemployment and interest rates have increased more recently and the Brazilian reais has weakened significantly in comparison to the US$. Our results of operations and financial condition may be adversely affected by the economic conditions in Brazil.

Petrobras and certain other Brazilian companies in the energy and infrastructure sectors are facing investigations by the Securities Commission of Brazil (Comissão de Valores Mobiliários), the U.S. Securities and Exchange Commission (the "SEC"), the Brazilian Federal Police and the Brazilian Federal Prosecutor's Office in connection with corruption allegations (the "Lava

Jato" investigations). Depending on the duration and outcome of such investigations, the companies involved may face downgrades from rating agencies, funding restrictions and a reduction in their revenues. Given the significance of the companies under investigation including Petrobras, this could adversely affect Brazil's growth prospects and could have a protracted effect on the oil and gas industry. In addition to the recent economic crisis, protests, strikes and corruption scandals have led to a fall in confidence.

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

The success of our business and the effective operation of the fields in each of our countries of operation depend upon continued good relations and cooperation with applicable governmental authorities and agencies, including national oil companies such as Ecopetrol, ENAP, Petrobras, Petroperu and YPF. For instance, for the year ended December 31, 2017, 100% of our crude oil and condensate sales in Chile were made to ENAP, the Chilean state-owned oil company. In addition, our Brazilian operations in BCAM-40 Concession provide us with a long-term off-take contract with Petrobras, the Brazilian state-owned company that covers 100% of net proved gas reserves in the Manati Field, one of the largest non-associated gas fields in Brazil. If we, the respective host governments and the national oil companies are not able to cooperate with one another, it could have an adverse impact on our business, operations and prospects.

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

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

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

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

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

The Colombian, Chilean, Brazilian, Peruvian and Argentine hydrocarbons industries are subject to extensive regulation and supervision by their respective governments in matters such as the environment, social responsibility, tort liability, health and safety, labor, the award of exploration and production contracts, the imposition of specific drilling and exploration obligations, taxation, foreign currency controls, price controls, capital expenditures and required divestments. In some countries in which we operate, such as Colombia, we are required to pay a percentage of our expected production to the government as royalties. See "Item 4. Information on the Company—B. Business Overview—Industry and regulatory framework—Colombia" and see Note 32(a) to our Consolidated Financial Statements.

For example, in Brazil there is potential liability for personal injury, property damage and other types of damages. Failure to comply with these laws and regulations also may result in the suspension or termination of operations or our being subjected to administrative, civil and criminal penalties, which could have a material adverse effect on our financial condition and expected results of operations. We expect to also operate in a consortium in some of our concessions, which, under the Brazilian Petroleum Law, establishes joint and strict liability among consortium members, and failure to maintain the appropriate licenses may result in fines from the ANP, ranging from R$10 to R$500 million. In addition, there is a contractual requirement in Brazilian concession agreements regarding local content, which has become a significant issue for oil and natural gas companies operating in Brazil given the penalties related with breaches thereof. The local content requirement will also apply to the production sharing contract regime. See "Item 4. Information on the Company—B. Business Overview—Our operations—Operations in Brazil."

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

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

In 2016, the Colombian government and the Revolutionary Armed Forces of Colombia (FARC) signed a peace agreement, pursuant to which the FARC agreed to demobilize its troops and to hand over its weapons to a United Nations mission within 180 days. Our business, financial condition and results of operations could be adversely affected by rapidly changing economic or social conditions, including the Colombian government's response to current peace agreements and negotiations with other groups, including the ELN, which may result in legislation that increases our tax burden or that of other Colombian companies.

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

In addition, from time to time, community protests and blockades may arise near our operations in Colombia, which could adversely affect our business, financial condition or results of operations.

Risks related to our common shares

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

Our common shares began to trade on the New York Stock Exchange (the "NYSE") on February 7, 2014, and as a result have a limited trading history. We cannot predict the extent to which investor interest in our company will maintain an active trading market on the NYSE, or how liquid that market will be in the future.
The market price of our common shares may be volatile and may be influenced by many factors, some of which are beyond our control, including:

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

We have never declared or paid, and do not expect to pay in the foreseeable future, cash dividends on our common shares, and, consequently, your only opportunity to achieve a return on your investment is if the price of our stock appreciates.

We have never paid, and do not expect to pay in the foreseeable future, cash dividends on our common shares. Any decision to pay dividends in the future, and the amount of any distributions, is at the discretion of our board of directors and our shareholders, and will depend on many factors, such as our results of operations, financial condition, cash requirements, prospects and other factors. Due to losses resulting from the oil price decline, accumulated losses amount to US$283.9 million as of December 31, 2017.

We are also subject to Bermuda legal constraints that may affect our ability to pay dividends on our common shares and make other payments. Under the Companies Act, 1981 (as amended) of Bermuda ("Bermuda Companies Act"), we may not declare or pay a dividend if there are reasonable grounds for believing that we are, or would after the payment be, unable to pay our liabilities as they become due or that the realizable value of our assets would thereafter be less than our liabilities. We are also subject to contractual restrictions under certain of our indebtedness.

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

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

We may not be able to fully control the operations and the assets of our joint ventures and we may not be able to make major decisions or take timely actions with respect to our joint ventures unless our joint venture partners agree. For example, we have entered into a shareholders' agreement and members' agreement with LGI in Chile and Colombia, respectively, that set the bases for the amount of dividends to be declared or returned to us, certain aspects related to the management of our Chilean and Colombian businesses, respectively, the incurrence of indebtedness, liens and our ability to sell certain assets. See "—Risks relating to our business—LGI, our strategic partner in Chile and Colombia, may not consent to our taking certain actions or may eventually decide to sell its interest in our Chilean and Colombian operations to a third party." We may, in the future, enter into other joint venture agreements imposing additional restrictions on our ability to pay dividends.

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

We may issue additional common shares or convertible securities in the future, for example, to finance potential acquisitions of assets, which we intend to continue to pursue. Sales of substantial amounts of our common shares in the public market, or the perception that these sales may occur, could cause the market price of our common shares to decline. This could also impair our ability to raise additional capital through the sale of our equity securities. Under our memorandum of association, we are authorized to issue up to 5,171,949,000 common shares, of which 60,596,219 common shares were outstanding as of December 31, 2017. We cannot predict the size of future issuances of our common shares or the effect, if any, that future sales and issuances of shares would have on the market price of our common shares.

Provisions of the Notes due 2024 could discourage an acquisition of us by a third party.

Certain provisions of the Notes due 2024 could make it more difficult or more expensive for a third party to acquire us, or may even prevent a third party from acquiring us. For example, upon the occurrence of a fundamental change, holders of the Notes due 2024 will have the right, at their option, to require us to repurchase all of their notes at a purchase price equal to 101% of the principal amount thereof plus any accrued and unpaid interest (including any additional amounts, if any) to the date of purchase. By discouraging an acquisition of us by a third party, these provisions could have the effect of depriving the holders of our common shares of an opportunity to sell their common shares at a premium over prevailing market prices.

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

Mr. Gerald E. O'Shaughnessy, our Chairman, Mr. James F. Park, our Chief Executive Officer, Mr. Jamie Coulter, director, and Mr. Juan Cristóbal Pavez, director, control 32.3% of our outstanding common shares as of March 15, 2018, holding the shares either directly or through privately held funds. As a result, these shareholders, if acting together, would be able to influence or control matters requiring approval by our shareholders, including the election of directors and the approval of amalgamations, mergers or other extraordinary transactions. They may also have interests that differ from yours and may vote in a way with which you disagree and which may be adverse to your interests. The concentration of ownership may have the effect of delaying, preventing or deterring a change of control of our company, could deprive our stockholders of an opportunity to receive a premium for their common shares as part of a sale of our company and might ultimately affect the market price of our common shares. See "Item 7. Major Shareholders and Related Party Transactions—A. Major shareholders" for a more detailed description of our share ownership.

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

As a foreign private issuer, the rules governing the information that we disclose differ from those governing U.S. corporations pursuant to the

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

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

We are an "emerging growth company," and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common shares less attractive to investors.

We are an "emerging growth company," as defined in the Jumpstart our Business Startups Act of 2012 (the "JOBS Act"), and for as long as we continue to be an "emerging growth company" we may choose to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not "emerging growth companies," including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404(b) of the Sarbanes Oxley Act. We cannot predict if investors will find our common shares less attractive because we will rely on these exemptions. If some investors find our common shares less attractive as a result, there may be a less active trading market for our common shares and our share price may be more volatile.

Under the JOBS Act, emerging growth companies can delay adopting new or revised accounting standards until such time as those standards apply to private companies. We have irrevocably elected not to avail ourselves of this exemption from new or revised accounting standards, and, therefore, we will be subject to the same new or revised accounting standards as other public companies that are not emerging growth companies.

Our internal controls over financial reporting may not be effective which could have a significant and adverse effect on our business and reputation.

We have evaluated our internal controls for our financial reporting and have determined our controls were effective for the fiscal year ended December 31, 2017. As long as we qualify as an "emerging growth company" as defined by the JOBS Act, we will not be required to obtain an auditor's attestation report on our internal controls in future annual reports on Form 20-F as otherwise required by Section 404(b) of the Sarbanes-Oxley Act. Accordingly, our independent registered public accounting firm did not perform an audit of our internal control over financial reporting for the fiscal year ended December 31, 2017. Had our independent registered public accounting firm performed an attestation on our internal control over financial reporting, it is possible that their opinion on our internal controls could have differed from ours which could harm our reputation and share value.

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

The Bermuda Monetary Authority (the "BMA"), must specifically approve all issuances and transfers of securities of a Bermuda exempted company like us unless it has granted a general permission. We are able to rely on a general permission from the BMA to issue our common shares, and to freely transfer our common shares as long as the common shares are listed on the NYSE and/or other appointed stock exchange, to and among persons who are non-residents of Bermuda for exchange control purposes. Any other transfers remain subject to approval by the BMA and such approval may be denied or delayed.

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

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

There is no treaty in force between the United States and Bermuda providing for the reciprocal recognition and enforcement of judgments in civil and commercial matters. As a result, whether a United States judgment would be enforceable in Bermuda against us or our directors and officers depends on whether the U.S. court that entered the judgment is recognized by the Bermuda court as having jurisdiction over us or our directors and officers, as determined by reference to Bermuda conflict of law rules. A judgment debt from a U.S. court that is final and for a sum certain based on U.S. federal securities laws will not be enforceable in Bermuda unless the judgment debtor had submitted to the jurisdiction of the U.S. court, and the issue of submission and jurisdiction is a matter of Bermuda (not U.S.) law.

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

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

In September 2012, Chile established "indirect transfer rules," which impose taxes, under certain circumstances, on capital gains resulting from indirect transfers of shares, equity rights, interests or other rights in the equity, control or profits of a Chilean entity, as well as on transfers of other assets and property of permanent establishments or other businesses in Chile ("Chilean Assets"). As we indirectly own Chilean Assets, the indirect transfer rules would apply to transfers of our common shares provided certain conditions outside of our control are met. If such conditions were present and as a result the indirect transfer rules were to apply to sales of our common shares, such sales would be subject to indirect transfer tax on the capital gain that may be determined in each transaction. For a description of the indirect transfer rules and the conditions of their application see "Item 10. Additional Information—E. Taxation—Chilean tax on transfers of shares."

ITEM 4. INFORMATION ON THE COMPANY

A. History and development of the company

General

We were incorporated as an exempted company pursuant to the laws of Bermuda as GeoPark Holdings Limited in February 2006. On July 30, 2013, our shareholders approved a change in our name to GeoPark Limited, effective from July 31, 2013. We maintain a registered office in Bermuda at Cumberland House, 9th Floor, 1 Victoria Street, Hamilton HM 11, Bermuda. Our principal executive offices are located at Nuestra Señora de los Ángeles 179, Las Condes, Santiago, Chile, telephone number +562 2242 9600, Street 94 N° 11-30, 8, 9, 8th floor, Bogotá, Colombia, telephone number +57 1 743 2337, and Florida 981, 1st floor, Buenos Aires, Argentina, telephone number +5411 4312 9400. Our website is www.geo-park.com. The information on our website does not constitute part of this annual report.

Our Company

We are a leading independent oil and natural gas exploration and production ("E&P") company with operations in Latin America and a proven track record of growth in production and reserves since 2006. We operate in Colombia, Chile, Brazil, Peru and Argentina. We are focused on Latin America because we believe it is one of the most important regions globally in terms of hydrocarbon potential, with less presence of independent E&P companies compared to the United Stated and Canada. In this region, much of the acreage has historically been controlled or owned by state-owned companies. We believe that these factors create an opportunity for smaller, more agile companies like us to build a long-term business.

We produced a net average of 27.6 mboepd during the year ended December 31, 2017, of which 79%, 10% and, 11% were, respectively, in Colombia, Chile, and Brazil, and of which 83% was oil. As of the third quarter of 2017, we were ranked as the second largest private oil operator in Colombia, where we made the largest new oil field discovery in the last 20 years. We are the first private oil and gas operator in Chile and we are operating the inaugural project of Petroperu in its return to the upstream business in Peru. We partnered with Petrobras in one of Brazil's largest producing gas fields and we have recently increased our activities in Argentina with a new oil field discovery and project acquisition.

We have built our company around three principal capabilities:

- as an Explorer, which is our ability, experience, methodology and creativity to find and develop oil and gas reserves in the subsurface, based on the best science, solid economics and ability to take the necessary managed risks.
- as an Operator, which is our ability to execute in a timely manner and to have the know-how to profitably drill for, produce, treat, transport and sell our oil and gas – with the drive and persistence to find solutions, overcome obstacles, seize opportunities and achieve results.
- as a Consolidator, which is our ability and initiative to assemble the right balance and portfolio of upstream assets in the right hydrocarbon basins in the right regions with the right partners and at the right price – coupled with the visions and skills to transform and improve value above ground.

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

Our regional platform and risk-balanced portfolio has been built following a proactive but conservative long term technical approach, converting projects into successful value-generating assets.

History

We were founded in 2002 by Gerald E. O'Shaughnessy and James F. Park, who have over 30 years of international oil and natural gas experience, respectively, and who collectively hold approximately 25% of our common shares as of the date of this annual report. Mr. O'Shaughnessy currently serves as our Chairman and Mr. Park currently serves as our Chief Executive Officer and Deputy Chairman.

In 2006, after demonstrating our technical expertise and committing to an exploration and development plan, we obtained a 100% operating working interest in the Fell Block from the Republic of Chile. Also in 2006, the International Finance Corporation (the "IFC"), a member of the World Bank Group, became one of our principal shareholders, and we listed our common shares on AIM, a market operated by the London Stock Exchange plc, in an initial public offering of common shares outside the United States. Subsequently, in 2008 and 2009, we issued and sold additional common shares outside the United States.

In 2008 and 2009, we continued our growth in Chile by acquiring operating working interests in each of the Otway and Tranquilo Blocks, and by forming partnerships with Pluspetrol, Wintershall, Methanex and IFC.

In 2010, we formed a strategic partnership with LGI, a Korean conglomerate, to jointly acquire and develop upstream oil and gas projects in Latin America. LGI's business includes a portfolio of energy and raw material projects, including oil and gas projects in the Middle East and in Southeast and Central Asia.

In 2011, ENAP awarded us the opportunity to obtain operating working interests in each of the Isla Norte, Flamenco and Campanario Blocks in Tierra del Fuego, Chile, which we refer to collectively as the Tierra del Fuego Blocks, and in 2012, jointly with ENAP, we entered into CEOPs with Chile for the exploration and exploitation of hydrocarbons within these blocks.

Also in 2011, LGI acquired a 20% equity interest in GeoPark Chile and a 14% equity interest in GeoPark TdF for US$148.0 million. Our agreement with LGI in the Tierra del Fuego Blocks allows us to earn back up to 12% equity participation in GeoPark TdF, depending on the success of our operations in Tierra del Fuego. See "Item 10. Additional Information—C. Material contracts."

In the first quarter of 2012, we moved into Colombia by acquiring three privately held E&P companies: (i) Winchester Oil and Gas S.A., a Colombian branch of a sociedad anónima incorporated under the laws of Panama, which merged into GeoPark Colombia SAS ("Winchester"), (ii) La Luna Oil Company Limited S.A., a sociedad anónima incorporated under the laws of Panama, which merged into GeoPark Colombia SAS ("Luna") and (iii) GeoPark Cuerva LLC, a limited liability company incorporated under the laws of the state of Delaware, which merged into GeoPark Colombia SAS ("Cuerva"). These acquisitions provided us with an attractive platform in Colombia that currently includes working interests and/or economic interests in 6 blocks located in the Llanos and Magdalena Basins. We have also a right to acquire and operate 85% of the Tiple Block in Colombia, subject to drilling an exploratory well resulting in a commercial discovery.

In December 2012, LGI acquired a 20% equity interest in GeoPark Colombia by making a US$14.9 million capital contribution and assuming the existing debt for an amount of US$4.9 million and the commitment to provide additional funding to cover LGI's share of required future investments in Colombia. Our agreement with LGI in Colombia allows us to earn back up to 12% equity participation in GeoPark Colombia, depending on the success of our operations in Colombia. See "Item 10. Additional Information—C. Material contracts." We believe our partnership with LGI represents a positive independent assessment and validation of the quality of our Chilean and Colombian asset inventory, the extent of our technical and operational expertise and the ability of our management to structure and effect significant transactions.

In February 2013, we issued US$300.0 million aggregate principal amount of 7.50% senior secured notes due 2020. We repurchased US$284.0 million aggregate principal amount of the outstanding Notes due 2020 in September 2017 and redeemed the remaining US$16.0 million aggregate principal amount outstanding in October 2017.

In May 2013, we entered into agreements to expand our operations to Brazil.

See "—B. Business Overview—Our operations—Operations in Brazil."
In February 2014, we commenced trading on the NYSE and raised US$98 million (before underwriting commissions and expenses), including the over-allotment option granted to and exercised by the underwriters, through the issuance of 13,999,700 common shares.

In August 2014, we and Pluspetrol were awarded two exploration licenses in the Sierra del Nevado and Puelen Blocks, as part of the 2014 Mendoza

Bidding Round in Argentina. The blocks are located in the Neuquén Basin, Argentina's largest producing hydrocarbon basin.

In October 2014, we entered into an agreement to expand our footprint into Peru through the acquisition of Morona Block in a joint operation with Petroperu. Petroperu awarded a 75% working interest in and operatorship of the Morona Block to us. The agreement was subject to regulatory approval, which was completed in December 2016, as described below.

In July 2015, we signed a farm-in agreement with Wintershall for the CN-V Block in Argentina.

In October 2015, we were awarded four exploratory blocks in the Brazilian ANP Bid Round 13 in the Reconcavo and Potiguar Basins.

In December 2015, as part of our long term effort to build an upstream platform in Mexico, we participated in the Mexican Bid Round 1.3 with Grupo Alfa for onshore projects, however, no blocks were awarded.

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

In September 2017, we issued US$425.0 million aggregate principal amount of 6.50% senior secured notes due 2024. The net proceeds from the Notes were used by us (i) to make a capital contribution to our wholly-owned subsidiary, GeoPark Latin America Limited Agencia en Chile, 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 a call premium, and (ii) for general corporate purposes, including capital expenditures, such as the acquisition of Aguada Baguales, El Porvenir and Puesto Touquet blocks in Neuquen basin in Argentina, and to repay existing indebtedness, including the Itaú loan. Additionally, we were awarded one exploratory block in the Brazilian ANP Bid Round 14 in the Potiguar Basin.

In December 2017, we agreed to purchase from Pluspetrol, a private oil and gas company with strong presence across Latin America, a 100% working interest and operatorship of the Aguada Baguales, El Porvenir and Puesto Touquet blocks in Argentina. We entered into an asset purchase agreement with Pluspetrol, dated December 18, 2017 (the "APA"). The transaction closed on March 27, 2018.

See "Item 3. Key Information—D. Risk factors—Risks relating to our business."

B. Business Overview

We are a leading independent oil and natural gas exploration and production ("E&P"), company with operations in Latin America and a proven track record of growth in production and reserves since 2006. We operate in Colombia, Chile, Brazil, Peru and Argentina.

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

The following map shows the countries in which we have blocks with working and/or economic interests as of December 31, 2017. For information on our working interests in each of these blocks, see "—Our assets" below.

(1) The Tiple Block is subject to drilling an exploratory well resulting in a commercial discovery. See "—Our operations—Operations in Colombia."
(2) The PN-T-597 is still subject to the entry into the concession agreement and absence of legal impediments, by the ANP in the Parnaíba Basin. See "—Our operations—Operations in Brazil."

The following table sets forth our net proved reserves and other data as of and for the year ended December 31, 2017.

For the year ended December 31 2017 [1] Country	Oil (mmbbl)	Gas (bcf)	Oil equivalent (mmboe)	%Oil	Revenues (in thousands of US$)	% of total revenues
Colombia	65.5	-	65.5	100%	263,076	80%
Chile	4.1	20.0	7.5	55%	32,738	10%
Brazil	0.1	23.8	4.0	3%	34,238	10%
Peru	18.7	-	18.7	100%	—	-%
Total	**88.4**	**43.8**	**95.7**	**92%**	**330,052**	**100%**

[1] Does not include Argentina, as reserves in Argentina have not been declared commercially viable as of December 31, 2017.

Our commitment to growth has translated into a strong compounded annual growth rate ("CAGR"), of 20% for production in the period from 2013 to 2017, as measured by boepd in the table below.

For the year ended December 31,	2017	2016	2015	2014	2013
Average net production (mboepd)	**27.6**	**22.4**	**20.4**	**19.7**	**13.5**
% oil	83%	75%	74%	74%	82%

The following table sets forth our production of oil and natural gas in the blocks in which we have a working and/or economic interest as of December 31, 2017.

Average daily production For the year ended December 31, 2017	Colombia	Chile	Brazil	Argentina	Total
Oil production					
Total crude oil production (bopd)	21,718	1,000	42	4	22,764
Natural gas production					
Total natural gas production (mcf/day)	414	11,317	17,209	-	28,940
Oil and natural gas production					
Total oil and natural gas production (mboed)	21,787	2,885	2,910	4	27,586

Our assets

We have a well-balanced portfolio of assets that includes working and/or economic interests in 24 hydrocarbon blocks, 23 of which are onshore blocks, including 7 in production as of December 31, 2017. Our assets give us access to more than 5 million gross exploratory and productive acres.

According to the D&M Reserves Report, as of December 31, 2017, the blocks in Colombia, Chile, Brazil and Peru in which we have a working interest had 95.7 mmboe of net proved reserves, with 68%, 8%, 4% and 20% of such net proved reserves located in Colombia, Chile, Brazil and Peru, respectively.

We produced a net average of 27.6 mboepd during the year ended December 31, 2017 of which 79%, 10%, and 11%, were in Colombia, Chile and Brazil, respectively, and of which 83% was oil.

We are the operator of a majority of the blocks in which we have a working interest.

Our strengths

We believe that we benefit from the following competitive strengths:

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

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

- Chile. In 2002, we acquired a non-operating working interest in the Fell Block in Chile, which at the time had no material oil and gas production or reserves despite having been actively explored and drilled over the course of more than 50 years. Since 2006, when we became the operator of the Fell Block we performed active exploration and development drilling that resulted in multiple oil and gas discoveries.
- Colombia. In 2012, we acquired assets in Colombia at attractive prices, which gave us access to exploratory and productive acres with high prospects. In the Llanos Basin, we pioneered a new play type combining structural and stratigraphic traps. As a result, in the Llanos 34 Block our average daily production has grown from 0 at the time of acquisition to more than 24,200 bopd as of December 31, 2017. During 2016, following the successful appraisal drilling in the Tigana and Jacana oil fields, we materially increased the field size.
- Brazil. In 2014, we acquired Rio das Contas, which gave us a 10% working interest in the BCAM-40 Concession, including the shallow-depth offshore Manati and Camarão Norte Fields in the Camamu-Almada Basin in the State of Bahia, which has consistently self-funded its operations. The Manati Field has provided up to 4.5% of total gas produced in Brazil.
- Argentina. During 2014, GeoPark and Pluspetrol were awarded two exploration licenses in the Sierra del Nevado and Puelen Blocks as part of the 2014 Mendoza Bidding Round in Argentina, carried out by Empresa Mendocina de Energía S.A. ("EMESA"). In 2015, we acquired a 50% working interest in Block CN-V in Mendoza from Wintershall Energía S.A. On December 18, 2017, we executed an asset purchase agreement (the "APA") with Pluspetrol, a private oil and gas company with strong presence across Latin America, to acquire a 100% working interest and operatorship of the Aguada Baguales, El Porvenir and Puesto Touquet blocks in Argentina. Closing of the transaction occurred on March 27, 2018.
- Peru. In December 2016, we expanded our footprint into Peru by acquiring the Morona Block in a joint venture with Petroperú. The Morona Block contains the Situche Central proven oil field, which we believe offers extensive exploration potential with several potential high impact prospects and plays. See "—Our operations—Operations in Peru."

Strong cash flow

We benefit from strong cash flow from operating activities. For the year ended December 31, 2017, cash provided by operating activities was US$142.2 million. Our cash flow from operating activities plays a significant role in funding our capital expenditures.

Significant drilling inventory and resource potential from existing asset base

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

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

Platform and Funding

We are focused on continued growth utilizing a disciplined capital structure and a conservative financial philosophy. Due to the volatile nature of commodity prices, fiscal discipline and a focus on disciplined capital structure are critical to our business. Our multi-country platform and asset portfolio is managed through our capital allocation methodology, which also allows us to quickly adapt and grow. Under this methodology, each country, has a local team running the business who recommends and advocates for the projects they want to move forward. The corporate team then ranks all of the projects based on economic, technical and strategic criteria, for the purpose of comparing projects. This also creates opportunities for improvements in the projects that can, in turn, improve their ranking. Finally, once the production and reserve growth targets are defined, the corporate team decides the amount of capital to be invested and allocates that capital to the highest value-adding projects. As an example, for the 2018 capital allocation process, over 100 projects were presented with a final selection of 50 which comprise our 2018 work program, under the preliminary base capital program. Additionally, given the inherent oil price volatility, we design our work programs to be flexible, which means that they can be increased or decreased depending on the oil price scenario.

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

We generated US$142.2 million and US$82.9 million in cash from operations in the years ended December 31, 2017 and 2016, respectively, and had US$134.8 million and US$73.6 million of cash and cash equivalents as of December 31, 2017 and 2016, respectively.

As of December 31, 2017, we had US$426.2 million of total outstanding indebtedness and over 99% of our debt had a maturity of 2024.

In February 2013, we issued US$300.0 million aggregate principal amount of 7.50% senior secured notes due 2020 (the "Notes due 2020"). We repurchased US$284.0 million aggregate principal amount of the outstanding Notes due 2020 in September 2017, and redeemed the remaining US$16.0 million aggregate principal amount outstanding in October 2017.

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

In March 2014, we borrowed US$70.5 million pursuant to a five-year term variable interest secured loan, secured by the benefits we receive under the Purchase and Sale Agreement for Natural Gas with Petrobras, equal to 6-month LIBOR + 3.9% to finance part of the purchase price of our Rio das Contas acquisition. In March 2015, we reached an agreement to: (i) extend the principal payments that were due in 2015 (amounting to approximately US$15 million), which were divided pro-rata during the remaining principal installments, starting in March 2016 and (ii) to increase the variable interest rate equal to the 6-month LIBOR + 4.0%. The loan was fully repaid in September 2017.

In December 2015, we entered into an offtake and prepayment agreement with Trafigura under which we sell and deliver a portion of our Colombian crude oil production to Trafigura. The offtake agreement also provides us with prepayment of up to US$100 million, subject to applicable volumes corresponding to the terms of the agreement, in the form of prepaid future oil sales. Following subsequent amendments, the availability period under the prepayment agreement was extended until September 30, 2017.
In September 2017, we issued US$425.0 million aggregate principal amount of 6.50% senior secured notes due 2024 (the "Notes due 2024"). The Notes due 2024 contain incurrence-based limitations on the amount of indebtedness we can incur See "Item 5. Operating and Financial Review and Prospects—Liquidity and capital resources—Indebtedness—Notes due 2024—Covenants."

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

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

Our CEO, Mr. James Park, has been involved in E&P projects in Latin America since 1978. He has been closely involved in grass-roots exploration activities, drilling and production operations, surface and pipeline construction, legal and regulatory issues, crude oil marketing and transportation and capital raising for the industry. As of March 15, 2018, Mr. Park held 13.0% of our outstanding common shares.

Our Chairman, Mr. Gerald O'Shaughnessy, has been actively involved in the oil and gas business internationally and in North America since 1976. As of March 15, 2018, Mr. O'Shaughnessy held 11.9% of our outstanding common shares. Our management and operating team has an average experience in the energy industry of more than 25 years in companies such as Chevron, ENAP, Petrobras, Pluspetrol, San Jorge, Total and YPF, among others. Throughout our history, our management and operating team has had success in unlocking unexploited value from previously underdeveloped assets.

In addition, as of March 15, 2018, our executive directors, management and employees (excluding our founding shareholders, Mr. Gerald E. O'Shaughnessy and Mr. James F. Park) owned 1.7% of our outstanding common shares, aligning their interests with those of our shareholders and helping retain the talent we need to continue to support our business strategy. See "Item 6. Directors, Senior Management and Employees—B. Compensation." Our founding shareholders are also involved in our daily operations and strategy.

Long-term strategic partnerships and strong strategic relationships, such as with LGI, provide us with additional funding flexibility to pursue further acquisitions
We benefit from a number of strong partnerships and relationships. In March 2010, we entered into a framework agreement with LGI, a Korean conglomerate, to establish a strategic growth partnership to jointly acquire and invest in oil and natural gas projects throughout Latin America. In May 2011, our partnership with LGI was strengthened by LGI's acquisition of a 10% equity interest in our existing Chilean operations. In October 2011, LGI acquired an additional 10% equity interest in GeoPark Chile and a 14% equity interest in GeoPark TdF, and agreed to provide additional financial support for the further development of the Tierra del Fuego Blocks. In December 2012, LGI acquired a 20% equity interest in our Colombian business. As of the date of this annual report, we believe we are the only independent E&P company in which LGI has equity investments in Latin America. See "—Significant Agreements—Agreements with LGI" for additional information relating to these agreements.

In addition, IFC has been one of our shareholders since 2006, holding a 5.7% equity interest in us as of December 31, 2017. In Chile, we believe we have strong long-term commercial relationships with Methanex and ENAP, and in Colombia, we believe we have developed a strong relationship with Ecopetrol, the Colombian state-owned oil and gas company. In Brazil, we believe we will continue to derive benefit from the long-term relationship GeoPark Brazil has with Petrobras.

On February 26, 2018, we announced the formation of a new long-term strategic partnership to jointly acquire, invest in, and create value from upstream oil and gas projects with the objective of building a large-scale, economically-profitable and risk-balanced portfolio of assets and operations across Latin America with the ONGC Videsh, the wholly-owned subsidiary and international arm of Oil and Natural Gas Corporation Limited ("ONGC"), India's national oil company.

2018 Strategy and Outlook

Oil prices were volatile since the end of 2014. In preparation for continued volatility, we have developed multiple scenarios for our 2018 capital expenditure program.

Our preliminary base capital program for 2018 considers a reference oil price assumption of US$50-55 per barrel and calls for approximately US$100-110 million to fund our exploration and development, which we intend to fund through cash flows from operations and cash-in-hand, to be allocated approximately as follows:

- Colombia: US$85-90 million. Focus on Llanos 34 Block to develop, appraise and further explore potential of the Tigana/Jacana oil play and target new exploration prospects in Llanos 34 block.
- Chile: US$1-2 million. Focus on business optimization as well as environmental and unconventional studies in the Fell Block.
- Brazil: US$3-4 million. Focus on exploration drilling in onshore blocks.
- Argentina: US$5-8 million. Focus on exploration drilling in CN-V, Sierra del Nevado and Puelen blocks in the Neuquen Basin.
- Peru: US$6-9 million. Focus on environmental impact studies and preliminary engineering works and facilities in the Morona block.

In addition, we have developed downside and upside work program scenarios based on different oil prices and project performance. The downside scenario work program considers a reference oil price assumption below US$50 per barrel and consists of an alternative capital expenditure program of approximately US$50 million-US$90 million consisting mainly of certain low risk and quick cash flow generating projects. The upside scenario work program considers a reference oil price assumption of US$60 per barrel or higher and consists of an alternative capital expenditure program of approximately US$120 million-US$150 million to be selected from identified projects designed to increase reserves and production.

Continue to grow a risk-balanced asset portfolio

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

For example, in Colombia, we acquired three companies simultaneously to pursue a risk-balanced approach: one company had mainly proven production and reserves to provide us with a steady cash flow base, and the remaining had highly prospective exploration license blocks. Within four years of entering Colombia, we made multiple oil discoveries in block Llanos 34 that allowed us to increase production and cash flows.

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

Maintain financial strength

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

Our cash flow generation is complemented by our financial hedging program. During 2016 and 2017, we entered into derivative financial instruments to manage our exposure to oil price risk. The purpose of our hedging strategy is to establish minimum oil prices to secure stable cash flow and the execution of our work program. For the period commencing January 2017 to December 2017, we hedged 12,000 bopd through a zero premium collar structure with a minimum average Brent price of US$52 per barrel and a maximum average price of US$58 per barrel, representing 53% of our oil production for that period. For the period from January 2018 to March 2018, we have secured 13,000 bopd with a minimum average price of US$51.4 per barrel and a maximum average price of US$52.8 per barrel via zero premium collars and three-way hedges (US$10/bbl wide put spread and call). For the period from April 2018 to June 2018, we have secured 10,000 bopd with a minimum average price of US$52.4 per barrel and a maximum average price of US$60.3 per barrel via zero premium collars and three-way hedges (US$10/bbl wide put spread and call). For the period commencing July 2018 to September 2018, we have secured 5,000 bopd with a minimum average price of US$53 per barrel and a maximum average price of US$69 per barrel via zero premium three-way hedges (US$10/bbl wide put spread and call).

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

Pursue strategic acquisitions in Latin America

We have historically benefited from, and intend to continue to grow through, strategic acquisitions in Latin America. These acquisitions have provided us with additional attractive platforms in the region. Our Colombian acquisitions, for example, highlight our ability to identify and execute on attractive growth opportunities, and we have grown to become the second largest private operator in Colombia. We acquired our interest in the Llanos 34 Block in the first quarter of 2012 for US$30 million and have achieved 1P reserve growth corresponding to PV-10 of US$814 million as of December 31, 2017. Our enhanced regional portfolio, primarily in investment-grade countries, and strong partnerships position us as a regional consolidator. We intend to continue to grow through strategic acquisitions and potentially in other countries in Latin America, which we may consider from time to time. Our acquisition strategy is aimed at maintaining a balanced portfolio of lower-risk cash flow-generating properties and assets that have upside potential, keeping a balanced mix of oil- and gas-producing assets (though we expect to remain weighted towards oil) and focusing on both assets and corporate targets.

Continue to foster a technically-driven culture and to capitalize on local knowledge

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

Maintain a high degree of operatorship to control production costs

As of the date of this annual report, we are and intend to continue to be the operator of a majority of the blocks and concessions in which we have working interests. Operating the majority of our blocks and concessions gives us the flexibility to allocate our capital and resources opportunistically and efficiently within a diversified asset portfolio. We believe that this strategy has allowed, and will continue to allow, us to leverage our unique culture, focus on excellence and our talented technical, operating and management teams. For example, as commodity prices were projected to decline throughout 2015, we announced in the first quarter of 2015 a decision to shift our development plan primarily to our operations in the Llanos 34 Block to focus on the Llanos Basin, which had demonstrated strong returns on capital. Our operating team reacted quickly to pivot our operations that were unburdened by drilling obligations and worked with our service partners to coordinate a smooth and efficient transition to a new plan. This has enabled us to control production costs, as our average operating costs for the Llanos 34 Block were US$4.3 per boe for the year ended December 31, 2017.

Maintain our commitment to environmental, safety and social responsibility

A major component of our business strategy is our focus on and commitment to our environmental and social responsibilities, in line with the IFC's standards. We see this as a fundamental element of ensuring long term business initiatives. We are committed to minimizing the impact of our projects on the environment and aim to create mutually beneficial relationships with the local communities in which we operate in order to enhance our ability to create sustainable value in our projects. These commitments are embodied in our in-house designed Environmental, Health, Safety and Security management program, which we refer to as "S.P.E.E.D." (Safety, Prosperity, Employees, Environment and Community Development). Our S.P.E.E.D. program was developed in accordance with several international quality standards, including ISO 14001 for environmental management issues, OHSAS 18001 for occupational health and safety management issues, ISO 26000 for social accountability and workers' rights issues, and applicable World Bank standards. See "—Health, safety and environmental matters."

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

In August 2017, we obtained the certification ISO 14001:2015 for our Environmental Management Process ("SGA") with the following scope: "Design, construction, operation, maintenance, modernization and dismantlement of GeoPark Colombia S.A.S.'s facilities, for the performance of exploration and oil and gas production activities in the Llanos 34 and VIM-3 blocks, with a commitment to continuously improve our processes."

Our operations

We have a well-balanced portfolio of assets that includes working and/or economic interests in 24 hydrocarbon blocks, 23 of which are onshore blocks, including 7 in production as of December 31, 2017, as well as in an additional shallow-offshore concession in Brazil that includes the Manati Field. In addition, we have one concession in Brazil, the PN-T-597 Block that is subject to the entry into the concession agreement by the ANP. We also have the right to acquire and operate 85% of the Tiple Block in Colombia, subject to drilling an exploratory well resulting in a commercial discovery.

Operations in Colombia

Our Colombian assets currently give us access to more than 248,300 gross exploratory and productive acres across 6 blocks in what we believe to be one of South America's most attractive oil and gas geographies.

Since we entered Colombia in 2012, we have achieved consistent growth in our oil production and proved reserves in Colombia, mainly achieved through successful exploration and development activities we made at our operated Llanos 34 Block, which as of December 31, 2017 accounts for 95% of our production and 99% of our proved reserves in Colombia.

The table below shows average production and proved oil reserves (derived from D&M Reserves Report) in Colombia for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
Average net production (mboepd)	21.8	15.5	13.2
Net proved reserves at year-end (mmbbl)	65.5	37.3	30.4

Highlights of the year ended December 31, 2017 related to our operations in Colombia included:

- Successful drilling campaign with 19 gross wells drilled and put into production in the Jacana and Tigana oil fields in the Llanos 34 Block;
- Discovery of the new Chiricoca oil field, following the successful drilling and testing of the Chiricoca 1 exploration well;
- Discovery of the new Jacamar oil field, located in a fault trend southeast of the Tigana/Jacana oil fields, following the successful drilling and testing of the Jacamar 1 exploration well. The well is producing from the Guadalupe formation. Oil shows during drilling and petrophysical analysis also indicate the potential for hydrocarbon production in the shallower Mirador and the deeper Gacheta formations;
- Discovery of the new Curucucu oil field, following the successful drilling and testing of the Curucucu 1 exploration well. To minimize surface construction costs and share production facilities, the Curucucu 1 exploration well was drilled from an existing well pad in the Jacamar oil field. The well was drilled with a horizontal extension of more than 9,000 feet, representing a record for the Llanos 34 block;
- Average net production increased by 41%, to 21.8 mboepd in 2017 from 15.5 mboepd in 2016;
- Proved oil reserves increased by 76% to 65.5 mmbbls at year-end 2017, from 37.3 mmbbls at year-end 2016 after producing 7.2 mmbbl;
- Capital expenditures increased by 205% to US$80.0 million in 2017 from US$26.2 million in 2016; and
- Maintenance of production and operating costs levels per barrel from US$5.4 in 2016 to US$5.6 in 2017.

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

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

The Tiple Block is subject to drilling an exploratory well resulting in a commercial discovery.

The table summarizes information about the blocks in Colombia in which we have working interests as of and for the year ended December 31, 2017.

Block	Gross acres (thousand acres)	Working interest[(1)]	Partners[(2)]	Operator	Net proved reserves (mmboe)[(3)]	Production (boepd)	Basin	Concession expiration year
Llanos 34	82.2	45.0%	Parex	GeoPark	63.6	20,676	Llanos	Exploration: 2017 Exploitation: 2039
La Cuerva	24.5	100.0%	—	GeoPark	1.1	585	Llanos	Exploration: 2014 Exploitation: 2038
Yamú	5.6	89.5/ 100%[(4)]	—	GeoPark	0.7	267	Llanos	Exploration: 2013 Production: 2036
Llanos 32	57.0	12.5%	Parex	Parex	0.1	209	Llanos	Exploration: 2015 Exploitation: 2039
VIM-3	46.9	100%	—	GeoPark	—	—	Magdalena	Exploration: 2021 Exploitation: 2045

[(1)] Working interest corresponds to the working interests held by our respective subsidiaries in such block, net of any working interests held by other parties in such block. LGI currently has a 20% direct equity interest in our Colombian operations through GeoPark Colombia SAS. However, we can earn back up to 12% additional equity interests in GeoPark Colombia depending on the success of our Colombian operations. See "—Significant Agreements—Agreements with LGI—LGI Colombia Agreements."
[(2)] Partners with working interests.
[(3)] As of December 31, 2017.
[(4)] Although we are the sole title holder of the working interest in the Yamú Block, other parties have been granted economic interests in fields in this block. Taking those other parties' interests into account, we have a 89.5% interest in the Carupana Field and a 100% interest in the Yamú and Potrillo Fields, both located in the Yamú Block.

The table summarizes information about the blocks in Colombia in which we have economic interests as of and for the year ended December 31, 2017.

Block	Gross acres (thousand acres)	Economic interest[(1)]	Operator	Production (boepd)	Basin
Abanico	32.1	10%	Pacific	50	Magdalena

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

Eastern Llanos Basin: (Llanos 34, La Cuerva, Yamú, Llanos 32, Llanos 17, Jagüeyes 3432A, Abanico, and VIM-3 Blocks)

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

Llanos 34 Block. We are the operator of, and have a 45% working interest in, the Llanos 34 Block, which covers approximately 82,200 gross acres (333 sq. km). We acquired an interest in and took operatorship of the block in the first quarter of 2012, which at the time had no production, reserves or wells drilled on it, and with 210 sq. km of existing 3D seismic data on which our team had mapped multiple exploration prospects. From 2012 to 2016 we engaged in exploration and development activities that resulted in multiple new oil fields discovered and increased production and proved reserves year by year until 2016. Average net production in 2016 was 14,890 bopd and net reserves of 37.1 mmbbl. The remaining commitment amounts to US$6.3 million at our working interest. As of the date of this Annual Report, we are awaiting the ANH's approval of US$3.6 million related to one well already drilled that was presented as fulfilment of the commitment to be performed before September 2019.

Our partner in the Llanos 34 Block is Parex, which has a 55% interest. See "—Our operations." We operate in the block pursuant to an E&P Contract with the ANH. See "—Significant Agreements—Colombia—E&P Contracts—Llanos 34 Block E&P Contract."

La Cuerva Block. We are the operator of, and have a 100% working interest in, the La Cuerva Block, which covers approximately 24,500 gross acres (99.1 sq. km). Due to the impact of low oil prices, we temporarily ceased operations in some fields during 2015 and 2016. Average net oil production in 2017 was 585 bopd. As of February 28, 2018, 22 wells were productive. We operate in the block pursuant to an E&P Contract with the ANH.

Yamú Block. We are the operator of, and have a 100% working interest in, the Yamú Block, which covers approximately 5,588 gross acres (22.6 sq. km). Economic rights to certain fields in the Yamú Block have been granted to other parties. In May 2013, we successfully drilled and completed the Potrillo 1 well.

For the year ended December 31, 2017, our average net production was 267 bopd. We resumed operations in this block in March 2017.

Llanos 17 Block. We had a 40% working interest in the Llanos 17 Block, which covered approximately 108,800 gross acres (440 sq. km) pursuant to an E&P Contract with the ANH. In October 2017, ANH confirmed that the contract was liquidated.

Llanos 32 Block. We have a 12.5% working interest in the Llanos 32 Block, as a result of our acquisition of an additional 2.5% interest on August 22, 2017. The Llanos 32 Block covers approximately 57,000 gross acres (230.7 sq. km). Parex is the operator of this block, and has a 70% working interest. Pluspetrol has a 20% working interest. Since 2015, the operator focused on the commissioning of a gas facility on this block to produce natural gas and light crude oil from the Une formation and to facilitate shipment of processed gas south to the adjacent Llanos 34 Block. For the year ended December 31, 2017, our average net production in the Llanos 32 Block was 209 bopd. The remaining commitment related to this block is to drill one exploratory well before August 2018 amounting to US$0.6 million at our working interest.

Jagüeyes 3432A Block. We had a 5% working interest in the Jagüeyes 3432A Block, which covered approximately 61,000 acres (247 sq. km). In December 2017, ANH confirmed that the contract was liquidated.

Abanico Block. In October 1996, Ecopetrol and Explotaciones CMS Nomeco Inc. entered into the Abanico Block association contract. Pacific is the operator of, and has a 100% working interest in, the Abanico Block, which covers an area of approximately 32,100 gross acres. We do not maintain a direct working interest in the Abanico Block, but rather have a 10% economic interest in the net revenues from the block pursuant to a joint operating agreement initially entered into with Kappa Resources Colombia Limited (now Pacific, who subsequently assigned its participation interest to Cespa de Colombia S.A., who then assigned the interest to Explotaciones CMS Oil & Gas), Maral Finance Corporation and Getionar S.A.

VIM-3 Block. On July 23, 2014 we were awarded a new exploratory license during the 2014 Colombia Bidding Round, carried out by the ANH. We are entitled to operate the block, in which we have a 100% working interest. The VIM-3 Block is located in the Lower Magdalena Basin, covering an area of approximately 225,000 acres. Our winning bid consisted of committing to a Royalty X Factor of 3% and a minimum investment program of 200 sq. km of 2D seismic data acquisition and drilling one exploratory well, with a total estimated investment of US$22.3 million during the initial exploratory period ending February 2019. On June 21, 2017, ANH approved our relinquishment of 79.15% of the VIM 3 Block area. The remaining area will cover 46,881 acres and the commitments described above are not affected.

Operations in Chile

Our Chilean assets currently give us access to 808,000 of gross exploratory and productive acres across 5 blocks in a large fully-operated land base across the Magallanes Basin, with existing reserves, production and cash flows.

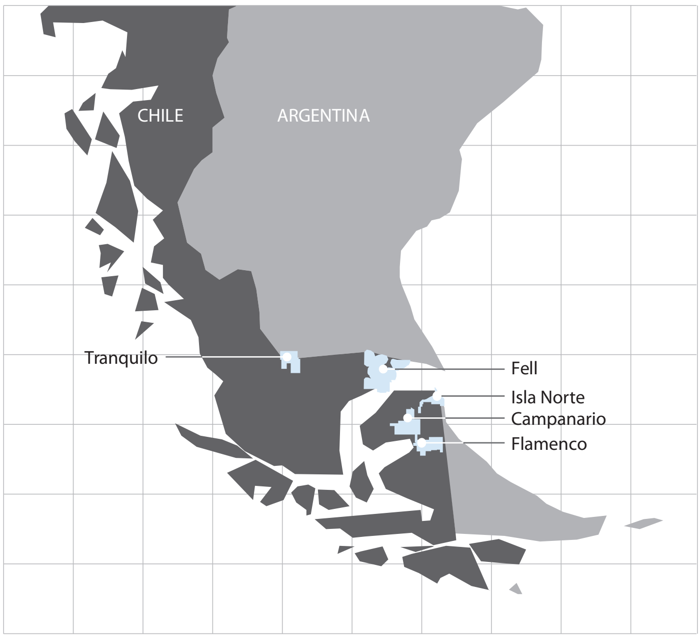
Our Chilean blocks are located in the provinces of Ultima Esperanza, Magallanes and Tierra del Fuego in the Magallanes Basin, a proven oil- and gas-producing area. As of December 31, 2017, the Magallanes Basin accounted for all of Chile's oil and gas production. Although this basin has been in production for over 60 years, we believe that it remains relatively underdeveloped.

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

Highlights of the year ended December 31, 2017 related to our operations in Chile included:

- Average net oil and gas production declined to 2,885 boepd in 2017 from 3,874 boepd in 2016;
- Proved oil and gas reserves decreased by 40% to 7.5 mmboe at year-end 2017, from 12.6 mmboe at year-end 2016 after producing 1.0 mmboe;
- Capital expenditures were increased by 31% to US$10.2 million in 2017 from US$7.8 million in 2016; and
- Drilling and completion of the Uaken 1 exploration well to a total depth of 3,658 feet. The Uaken gas field discovery in the shallower El Salto formation provides additional low-cost production and creates a new gas play across the Fell block that can be tested in identified leads and prospects. In addition, there are multiple wells in already discovered oil and gas fields within the Fell block that can be re-entered to test this formation.
- Successful cost reduction efforts impacting production and operating costs that represented a 5% reduction, to US$21.0 million in 2017 as compared to US$22.2 million in 2016.

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



The table below summarizes information about the blocks in Chile in which we have working interests as of and for the year ended December 31, 2017.

Block	Gross acres (thousand acres)	Working interest[(1)]	Partners[(2)]	Operator	Net proved reserves (mmboe)[(3)]	Production (boepd)	Basin	Concession expiration year
Fell	367.8	100%	—	GeoPark	7.3	2,835	Magallanes	Exploitation: 2032
Tranquilo	92.4	50%	Pluspetrol	GeoPark	—	—	Magallanes	Exploitation: 2043
Isla Norte	97.7	60%[(4)]	ENAP	GeoPark	—	—	Magallanes	Exploration: 2021 Exploitation: 2044
Campanario	144.2	50%[(4)]	ENAP	GeoPark	—	—	Magallanes	Exploration: 2021 Exploitation: 2045
Flamenco	105.9	50%[(4)]	ENAP	GeoPark	0.2	50	Magallanes	Exploration: 2021 Exploitation: 2044

(1) Working interest corresponds to the working interests held by our respective subsidiaries in such block, net of any working interests held by other parties in such block. LGI has a 20% direct equity interest in our Chilean operations through GeoPark Chile. See "—Significant Agreements—Agreements with LGI—LGI Chile Shareholders' Agreements."

(2) Partners with working interests.

(3) As of December 31, 2017.

(4) LGI has a 14% direct equity interest in our Tierra del Fuego operations through GeoPark TdF and a 20% direct equity interest in GeoPark Chile, for a total effective equity interest of 31.2% in our Tierra del Fuego operations. See "—Tierra del Fuego Blocks (Isla Norte, Campanario and Flamenco Blocks)" and "—Significant Agreements—Agreements with LGI—LGI Chile Shareholders' Agreements."

Fell Block

In 2006, we became the operator and 100% interest owner of the Fell Block. When we first acquired an interest in the Fell Block in 2002, it had no material oil and gas production. Since then, we have completed more than 1,100 sq. km of 3D seismic surveys and drilled 117 exploration and development wells. In the year ended December 31, 2017, we produced an average of 2,835 boepd, in the Fell Block, consisting of 54% oil.

The Fell Block has an area of approximately 368,000 gross acres (1,488 sq. km) and its center is located approximately 140 km northeast of the city of Punta Arenas. It is bordered on the north by the international border between Argentina and Chile and on the south by the Magellan Strait.

From 2006 through August 2011, we successfully explored and developed the Fell Block, which allowed us to transition approximately 84% of the Fell Block's area from an exploration phase into an exploitation phase, which we expect will last through 2032. During the exploration phase, we exceeded the minimum work and investment commitment required under the Fell Block CEOP by more than 75 times. There are no minimum work and investment commitments under the Fell Block CEOP associated with the exploitation phase.

The Fell Block is located in the north-eastern part of the Magallanes Basin. The principal producing reservoir is composed of sandstones in the Springhill formation, at depths of 2,200 to 3,500 meters. Additional reservoirs have been discovered and put into production in the Fell Block—namely, Tobífera formation volcanoclastic rocks at depths of 2,900 to 3,600 meters, and Upper Tertiary and Upper Cretaceous sandstones, at depths of 700 to 2,000 meters. Our geosciences team identified and developed an attractive inventory of prospects and drilling opportunities for both exploration and development in the Fell Block. Previous oil discoveries in the Konawentru, Yagán, Yagán Norte, Copihue and Guanaco fields have opened up new oil and gas potential in the Fell Block. An important discovery during 2011 was the Konawentru 1 well, which we initially tested to have in excess of 2,000 bopd from the Tobífera formation, and which has opened up additional potentially attractive opportunities (workovers, well-deepening's and new exploration and development wells) in the Tobífera formation throughout the Fell Block. From 2012 to 2014, we focused our exploration and development plan in the Tobífera formation by drilling wells in Konawentru, Yagán and Yagán Norte fields, as well as deepening existing wells in Ovejero and Molino. Exploration efforts in 2014 resulted in the discoveries of the Ache gas field and the Loij oil field.

During 2015, although there were no wells drilled, we put into production a new gas field, Ache, that was discovered in 2014. During 2016, we successfully drilled the Pampa Larga 16 well and continued focusing on maintaining production levels and reducing production and operating costs. During 2017, we drilled three wells; two of them were put into production (Kimiriaike 4 and Uaken X-1) and the remaining well (Ache-3) is still under evaluation. In addition, we continued to focus on maintaining production levels and reducing production and operating costs.

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

In February 2018, Methanex announced the reopening of their second plant in Punta Arenas, which is estimated to reopen by the end of the third quarter of 2018.

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

In the first and second quarters of 2012, we entered into three CEOPs with ENAP and Chile granting us working interests in the Isla Norte, Campanario and Flamenco Blocks, located in the center-north of the Tierra del Fuego province of Chile. We are the operator of all three of these blocks, with working interests of 60%, 50% and 50%, respectively. We believe that these three blocks, which collectively cover 347,700 gross acres (1,407 sq. km) and are geologically contiguous to the Fell Block, represent strategic acreage with resource potential. We have committed to paying 100% of the required minimum investment under the CEOPs covering these blocks, in an aggregate amount of US$101.4 million through the end of the first exploratory periods for these blocks, which occurred in November 2015 for the Flamenco Block, in May 2017 for the Isla Norte Block and in July 2017 for the Campanario Block, which includes our covering of ENAP's investment commitment corresponding to its working interest in the blocks. Under Article 5.3 of CEOP, at the end of the first exploration period, the contractor defines the area to be retained and we were required to return to the state at least 25% of the original area of the contract. The first exploration period of Isla Norte and Campanario Blocks ended in 2017, at which point we relinquished 80.6 gross acres (583 sq. km).

Isla Norte Block . We are the operator of, and have a 60% working interest in partnership with ENAP in the Isla Norte Block, which covers approximately 97,650 gross acres (395 sq. km). As of March 2018, we had completed 100% of the committed 350 sq. km of 3D seismic surveys and drilled one exploratory well, which represents the first oil discovery within the block. As of the date of this annual report, outstanding investment commitments of US$2.9 million related to this block correspond to two exploratory wells to be executed before May 7, 2019.

Campanario Block . We are the operator of, and have a 50% working interest in, the Campanario Block, in partnership with ENAP. The block covers approximately 144,150 gross acres (583 sq. km). As of March 31, 2018, we had completed 100% of the committed 578 sq. km of 3D seismic surveys and have also drilled five exploratory wells, including the Primavera Sur 1 well that marks the first discovery of an oil field on the Campanario Block in addition to one development well. As of the date of this annual report, outstanding investment commitments of US$4.8 million related to this block correspond to three exploratory wells to be executed before July 10, 2019.

Flamenco Block . We are the operator of, and have a 50% working interest in, the Flamenco Block, in partnership with ENAP. The block covers approximately 105,900 gross acres (428 sq. km). In June 2013, we discovered a new oil and gas field in the block following the successful testing of the Chercán 1 well, the first well drilled by us in Tierra del Fuego. As of March 31, 2018, we had completed 100% of the committed 570 sq. km of 3D seismic surveys. We have also committed to drilling ten wells during the first exploration period under the CEOP governing the Flamenco Block. In the year ended December 31, 2017, we produced an average of 50 boepd in the Flamenco Block.

On June 30, 2017, the Chilean Ministry accepted our proposal to extend the second exploratory period for an additional period of 18 months. As of the date of this annual report, outstanding investment commitments related to this block correspond to 1 exploratory well until May 7, 2019 for US$2.1 million, to be assumed 100% by us.

Otway and Tranquilo Blocks

In relation to the Otway Block, we have informed the Ministry of Energy the termination of the CEOP due to the fact that the two provisional areas of Tatiana and Cabo Negro have expired in September and October 2017, respectively. There were no pending obligations at the end of the CEOP.
We are the operator of the Tranquilo Block.
In the Tranquilo Block, as of December 31, 2017, we had a 50% working interest alongside our partner Pluspetrol.

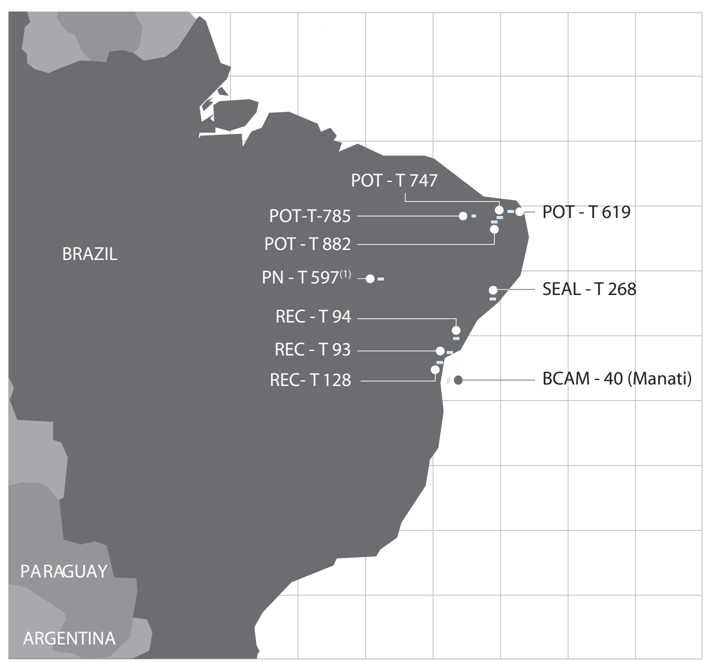
In the Tranquilo Block we completed a seismic program consisting of 163 sq. km of 3D seismic and 371 sq. km of 2D seismic survey work, and drilled four wells, including the Palos Quemados and Marcou Sur well. We discovered gas in the El Salto formation of the Palos Quemado well. At the Palos Quemados well, we completed a 22-week commercial feasibility test aimed at defining its productive potential. As the test was not conclusive, we were granted permission by the Chilean Ministry of Energy to extend the testing period for an additional six months. Upon such testing period, we kept 4 provisional protection areas, which enabled continued analysis of the area prior the declaration of its commercial viability for a period of 5 years. On January 17, 2013, we formally announced to the Chilean Ministry of Energy our decision not to proceed with the second exploratory period and to terminate the exploratory phase of the Tranquilo Block CEOP. Subsequently, we relinquished all areas of the Tranquilo Block, except for a remaining area of 92,417 gross acres, for the exploitation of the Renoval, Marcou Sur, Estancia Maria Antonieta and Palos Quemados Fields, which we have identified as the areas with the most potential for prospects in the block. In November 2017, we proposed to the Ministry of Energy to extend the period to declare the commerciality of discoveries in the areas of Palos Quemados, Maria Antonieta and Marcou Sur for an additional period of 24 months. In February 2018, the Ministry approved our proposal.

Operations in Brazil

Our Brazilian assets currently give us access to 84,300 of gross exploratory and productive acres across 9 blocks (8 exploratory blocks and the BCAM-40 Concession, which is in production phase) in an attractive oil and gas geography. Highlights of the year ended December 31, 2017 related to our operations in Brazil included:

- Average net oil and gas production of 2,910 boepd (99% gas) in the year ended December 31, 2017, as compared to 2,930 boepd in 2016;
- Capital expenditures remained at US$3.6 million in 2017;
- Praia do Espelho exploration prospect in Reconcavo Basin was drilled to a total depth of 7,654 feet. Main targets, Sergi and Agua Grande formations, were found to be water bearing with reservoir thicknesses of 36 feet and 46 feet, respectively. In addition, 47 feet of reservoir with oil traces were encountered in a secondary target, in the Gomo formation. Following an in-depth geological and geophysical analysis, a decision was made to plug and abandon the well during the second quarter of 2017; and
- A new block awarded in Round 14 (POT-T-785 Block).

The map below shows the location of our concessions in Brazil in which we have a current or future working interest, including the BCAM-40 Concession and the concessions from bidding rounds 11, 12, 13 and 14.



[1] The PN-T-597 Block is subject to an injunction and our bid for the concession has been suspended. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—The PN-T-597 Concession Agreement in Brazil may not close."

The following table sets forth information as of December 31, 2017 on our concessions in Brazil in which we have a current or future working interest, including the BCAM-40 Concession and the concessions from bidding rounds 11, 12, 13 and 14.

Concession	Gross acres (thousand acres)	Working interest[1]	Partners	Operator	Net proved reserves (mmboe)[3]	Production (boepd)	Basin	Concession expiration year
REC-T 94	7.7	100%	—	GeoPark	—	—	Recôncavo	Exploration: 2020 Exploitation: 2047
POT-T 619	7.9	100%	—	GeoPark	—	—	Potiguar	Exploration: 2018 Exploitation: 2045
PN-T-597[4]	188.7	100%	—	GeoPark	—	—	Parnaíba	—
SEAL-T-268	7.8	100%	—	GeoPark	—	—	Sergipe Alagoas	Exploration: 2020 Exploitation: 2047
REC-T-93	7.8	100%	—	GeoPark	—	—	Recôncavo	Exploration: 2018 Exploitation: 2045
REC-T-128	7.6	70%	Geosol	GeoPark	—	—	Recôncavo	Exploration: 2018 Exploitation: 2045
POT-T-747	6.9	100%[5]	—	GeoPark	—	—	Potiguar	Exploration: 2018 Exploitation: 2045
POT-T-882	7.9	100%[5]	—	GeoPark	—	—	Potiguar	Exploration: 2018 Exploitation: 2045
POT-T-785	7.9	100%[5]	—	GeoPark	—	—	Potiguar	Exploration: 2023 Exploitation: 2050
BCAM-40	22.8	10%	Petrobras; QGEP; Brasoil	Petrobras	4.0	2,910	Camamu-Almada	Exploitation: 2029[2] - 2034[3]

(1) Working interest corresponds to the working interests held by our respective subsidiaries, net of any working interests held by other parties in such concession. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—The PN-T-597 Concession Agreement in Brazil may not close."
(2) Corresponds to Manati Field.
(3) Corresponds to Camarão Norte Field.
(4) PN-T-597 Block subject to the entry into the concession agreement by the ANP and absence of any legal impediments to signing. As of the date of this annual report, confirmation remains subject to final signing and local authority approval. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—The PN-T-597 Concession Agreement in Brazil may not close."
(5) A 30% working interest of proposed partners is subject to ANP approval.

BCAM-40 Concession

As a result of the Rio das Contas acquisition, we have a 10% working interest in the BCAM-40 Concession, which includes interests in the Manati Field and the Camarão Norte Field, and which is located in the Camamu-Almada Basin. Petrobras is the operator, and has a 35% working interest in, the BCAM-40 Concession, which covers approximately 22,784 gross acres (92.2 sq. km). In addition to us, Petrobras' partners in the block are Brasoil and QGEP, with 10% and 45% working interests, respectively. Petrobras operates the BCAM-40 Concession pursuant to a concession agreement with the ANP, executed on August 6, 1998. See "—Significant Agreements—Brazil—Overview of concession agreements—BCAM-40 Concession Agreement." In September 2009, Petrobras announced the relinquishment of BCAM-40's exploration area within the concession to the ANP, except for the Manati Field and the Camarão Norte Field.

The Manati Field is located 65 km south of Salvador, offshore at a 35 meter water depth. The field was discovered in October 2000, and, in 2002, Petrobras declared the field commercially viable. Production began in January 2007. As of December 31, 2017, 11 wells had been drilled in the Manati Field, six of which are productive and connected to a fixed production platform installed at a depth of 35 meters, located 9 km from the coast of the State of Bahia. From the platform, the gas flows by sea and land through a 125 km pipeline to the Estação Vandemir Ferreira or EVF gas treatment plant. The gas is sold to Petrobras up to a maximum volume as determined in the existing Petrobras Gas Sales Agreement (as defined below). In July 2015, we signed an amendment to the existing Gas Sales Agreement with Petrobras that covers 100% of the remaining gas reserves of the Manati Field.

Also in 2015, in order to improve the field gas recovery and production, Manatì's consortium built an onshore compression plant that started operating in August 2015. The compression plant involved capital expenditures of approximately US$3.7 million at our working interest and allowed us to classify all existing proved undeveloped reserves as proved developed as of December 31, 2016.

Some environmental licenses related to operation of the Manati Field production system and natural gas pipeline are expired. However, the operator submitted, in a timely manner, the request for renewal of those licenses and as such this operation is not in default as long as the regulator does not state its final position on the renewal. The Camarão Norte Field is in the development phase and is not yet subject to the environmental licensing requirement.

Round 11 Concessions

During ANP's 11th Bid Round, held in May 2013, we were awarded 7 exploratory blocks, of which 2 were in the Reconcavo Basin in the state of Bahia and 5 were in the Potiguar Basin in the state of Rio Grande do Norte. The exploratory phase for these concessions is divided into two exploratory periods, the first of which lasts for three years and the second of which is non-obligatory and can last for up to two years.

In 2016, after fulfilling the committed exploratory commitments and further reevaluation of commercial potential, five exploratory blocks were relinquished to the ANP (REC T 85, POT T 620, POT T 663, POT T 664 and POT T 665).

REC-T 94 Concession

In the REC-T 94 we committed R$17.6 million (approximately US$5.3 million, at the December 31, 2017 exchange rate of R$3.3 to US$1.00) during the first exploratory period consisting of drilling two exploratory wells and 31 sq. km of 3D seismic surveys.

During the year 2014 we executed a 3D seismic survey. Seismic data interpretation in 2015 and 2016 defined two well locations, one of which was drilled in 2017. The estimated remaining commitment amounts to US$0.9 million.

POT-T 619 Concession

In the POT-T 619 Concession we committed investments of R$2.3 million (approximately US$0.7 million at the December 31, 2017 exchange rate of R$3.3 to US$1.00) during the first exploratory period, equivalent to 46 km of 2D seismic work.

During the year 2014 we executed a 2D seismic survey. Seismic data processing was concluded in 2015. After seismic interpretation, we decided to continue to the second exploratory period in September 2016, which lasts for two years with a commitment to drill one exploratory well. The well was drilled during 2018 and was abandoned. There is no pending commitment.

Round 12 Concessions

In November 2013, in the 12th Bid Round, the ANP awarded us two new concessions (the PN-T-597 Concession in the Parnaíba Basin in the State of Maranhão and the SEAL-T-268 Concession in the Sergipe Alagoas Basin) in the State of Alagoas.

For more information, see "Item 3. Key information—D. Risk factors—Risks relating to our business—The PN-T-597 Concession Agreement in Brazil may not close."

PN-T-597 Concession

The Parnaiba Basin, which covers an area of approximately 148 million gross acres (600,000 sq. km), is a basin with large underexplored areas. As of December 31, 2017, the basin had two fields in production in the basin.

In the PN-T-597 Concession we committed R$7.7 million (approximately US$2.3 million, at the December 31, 2017 exchange rate of R$3.3 to US$1.00) for the first exploratory period, equivalent to 180 km of 2D seismic.

The exploratory phase for this concession is divided into two exploratory periods. Given that Parnaiba Basin is considered as a "new frontier" area by the ANP, the first exploratory period lasts four years, and the second exploratory period, which is optional, can last for up to two years.

See "Item 3. Key Information—D. Risk factors—Risks relating to our business—The PN-T-597 may not close" and "—D. Risk factors—Risks relating to the countries in which we operate—Our operations may be adversely affected by political and economic circumstances in the countries in which we operate and in which we may operate in the future" for more information.

SEAL-T-268 Concession

In the SEAL-T-268 Concession we committed R$1.6 million (approximately US$0.5 million, at the December 31, 2017 exchange rate of R$3.3 to US$1.00) for the first exploratory period. The exploratory phase for this concession is divided into two exploratory periods, the first lasting three years, and the second, which is optional, can last for up to two years. During 2016, an electromagnetic survey acquisition of 70 stations and reprocessing of 58 km of vintage 2D seismic was performed and, after ANP approval of the extension of the first exploratory phase, we will fulfill part of the remaining committed work program that amounts to US$ 0.2 million.

Round 13 Concessions

During ANP's 13th Bid Round held in October 2015, we were awarded four exploratory concessions, of which two were in the Potiguar Basin in the state of Rio Grande do Norte and two were in the Reconcavo Basin in the state of Bahia. The exploratory phase for these concessions is divided into two exploratory periods, the first of which lasts for three years and the second of which is non-obligatory and can last for up to two years.

POT-T-747 and POT-T-882

The POT-T-747 and POT-T-882 blocks are located in the Potiguar Basin and encompass an area of 14,829 acres (60 square km). Total commitment to the ANP was R$8.5 million (approximately US$2.6 million, at the December 31, 2017 exchange rate of R$3.3 to US$1.00) during the first exploratory period and is equivalent to acquiring 70 km of 2D seismic, and drilling one well. During 2017 3D seismic was reprocessed and a well was drilled in the POT-T-747 block during 2018 and was abandoned. The estimated remaining commitment amounts to US$0.2 million.

REC-T-128 and REC-T-93

Both blocks are part of the Reconcavo Basin and have a combined area of 15,405 acres (62.3 square km). The block REC-T-128 was bid for in partnership with Geosol with a 70% working interest for us and 30% working interest for Geosol. The total commitment to the ANP was R$10.7 million (approximately US$3.2 million at the December 31, 2017 exchange rate of R$3.3 to US$1.00) during the first exploratory period and consists of acquiring 9 km2 of 3D seismic, drilling one well and performing geochemical analysis at two levels.

During 2016, regional interpretation studies were performed in the area. Part of the minimum exploratory program of Block REC-T-93 has been fulfilled and approved by ANP with the 3D regional seismic acquisition which also covered Block REC T 94 (Round 11). During 2017, 3D reprocessing was performed in the REC-T-128 block. The estimated remaining commitment amounts to US$2.9 million.

Round 14 Concessions

During ANP's 14th Bid Round held in September 2017, we were awarded one exploratory concession, in the Potiguar Basin in the state of Rio Grande do Norte.

POT-T-785

The POT-T-785 block covers an area of 7,875 acres in the Potiguar Basin, surrounded by producing fields operated by Petrobras. Total commitment to the ANP was R$1.2 million (US$0.4 million, at the December 31, 2017 exchange rate of R$3.3 to US$1.00) during the first exploratory period and is equivalent to acquiring 4 km2 of 3D seismic, and performing geochemical analysis.

Operations in Peru

In October 2014, we entered into an agreement to expand our footprint into Peru (our fifth country platform in Latin America) through the acquisition of Morona Block in a joint venture with Petroperu.

The Morona Block has DeGolyer and MacNaughton certified net proved reserves of 18.7 mmboe as of December 31, 2017, composed of 100% oil.

The map below shows the location of the Morona Block in Peru.

The table below summarizes information about the block in Peru.

Block	Gross acres (thousand acres)	Working interest[(1)]	Operator	Net proved reserves (mmboe)[(2)]	Production (boepd)	Basin	Expiration concession year
Morona	1,881	75%	GeoPark	18.7	—	Marañon	Exploitation: 2038 [(3)]

(1) Corresponds to the initial working interest. Petroperu will have the right to increase its working interest in the block by up to 50%, subject to the recovery of our investments in the block through agreed terms in the Petroperu SPA. See "Item 4. Information on the Company—B. Business Overview—Our operations—Operations in Peru—Morona Block."
(2) Certified by DeGolyer and MacNaughton as of December 31, 2017.
(3) The concession will expire twenty (20) years after EIA approval.

Morona Block
The Morona Block covers an area of approximately 1,881 thousand gross acres (7,600 sq. km). More than 1 billion barrels of oil have been produced from the surrounding blocks in the Marañon Basin.

On October 1, 2014, we entered into an agreement to acquire a 75% working interest in the Morona Block in Northern Peru. As stated above, this agreement includes a work program to be executed by us. This program includes 3 phases, and we may decide whether to continue or not at the end of each phase. On December 1, 2016, through Supreme Decree N° 031-2016-MEN, the Peruvian government approved the amendment to the License Contract of Morona Block appointing GeoPark as operator and holder of 75% of the License-Contract.

The Morona Block 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 addition to the Situche Central field, the Morona Block has a large exploration potential with several high impact prospects and plays. The Morona Block includes geophysical surveys of 2,783 km (2D seismic) and 465 sq. km (3D seismic), and an operating field camp and logistics infrastructure. The area has undergone oil and gas exploration activities for the past 40 years, and there exist ongoing association agreements and cooperation projects with the local communities. The expected work program and development plan for the Situche Central oil field is to be completed in three stages.

The goal of the initial two stages is to start production from the two wells already drilled in the field, in order to determine the most effective overall development plan and to begin to generate cash flow. These initial stages require an investment of approximately US$100 million to US$150 million and are expected to be completed by the first half of 2020. We have committed to carry Petroperu, by paying its portion of the required investment in these initial phases. In addition, we are required to cover any capital or operational expenditures of Petroperu associated with the project until December 31, 2020. We expect these expenditures to be substantially reimbursed by Petroperu from revenues associated to future sales.

In accordance with the agreement between us and Petroperu, commitments assumed by GeoPark are subject to certain economical and technical conditions being met.

The third stage, which will be initiated once production has been established, is expected to focus on carrying out the full development of the Situche Central field, including transportation infrastructure.

The exploratory program entails drilling one exploratory well. Exploratory program capital expenditures will be borne exclusively by us. Expected capital expenditures in 2018 for the Morona Block are mainly related to facility maintenance and environmental and engineering studies in order to get the approval of the Development Environmental Impact Study by the end of the year.

Initially we will hold a 75% working interest in the block. However, according to the terms of the agreement, Petroperu has the right to increase its working interest in the block by up to 50%, subject to the recovery of our investments in the block by certain agreed factors.
See "Item 3. Key Information—D. Risk factors—Risks relating to our business—"Our inability to access needed equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets and generate significant incremental costs or delays in our oil and natural gas production" and "—We may suffer delays or incremental costs due to difficulties in negotiations with landowners and local communities, including native communities, where our reserves are located."

Operations in Argentina

The map below shows the location of the blocks in Argentina in which we have working interests as of December 31, 2017.

The table below summarizes information about the blocks in Argentina in which we have working interests as of December 31, 2017.

Block	Gross acres (thousand acres)	Working interest[1]	Operator	Net proved reserves (mmboe)[2]	Production (boepd)	Basin	Expiration concession year
Puelen	305.4	18%	Pluspetrol	—	—	Neuquén	Exploration: 2020
Sierra del Nevado	1,433.2	18%	Pluspetrol	—	—	Neuquén	Exploration: 2020
CN-V	117.0	50%	GeoPark	—	4	Neuquén	Exploration: 2018

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

[2] As of December 31, 2017.

Highlights of the year ended December 31, 2017 related to our operations in Argentina included:

- Discovery of the Rio Grande Oeste oil field in CN-V block following the successful drilling and testing of the exploratory well Rio Grande Oeste 1; and
- Execution of an asset purchase agreement with Pluspetrol to acquire 100% working interest and operatorship of the Aguada Baguales, El Porvenir and Puesto Touquet blocks ("the blocks") for a total consideration of US$52 million. The blocks include:
  - estimated oil and gas production of approximately 2,700 boepd - 70% light oil and 30% gas;
  - 137,000 acres in the Neuquen Basin; and
  - production facilities, including hydrocarbons treatment, storage, and delivery infrastructure.

2014 Mendoza Bidding Round

On August 20, 2014, the consortium of Pluspetrol and us was awarded two exploration licenses in the Sierra del Nevado and Puelen Blocks, as part of the 2014 Mendoza Bidding Round in Argentina, carried out by Empresa Mendocina de Energía S.A. ("EMESA").

The consortium consists of Pluspetrol (operator with a 72% working interest), EMESA (non-operator with a 10% working interest) and us (non-operator with an 18% working interest). In accordance with the terms of the bidding, all of the expenditures related to EMESA's working interest will be carried by Pluspetrol and us proportionately to our respective working interests, and will be recovered through EMESA's participation in future potential production.

Puelen Block : The Puelen Block covers an area of approximately 305.4 thousand gross acres, and is located in the Neuquén Basin in southern Argentina.

Sierra del Nevado Block : The Sierra del Nevado Block covers an area of approximately 1,433.2 thousand gross acres, and is located in the Neuquén Basin in southern Argentina.

We have committed to a minimum aggregate investment of US$6.2 million for our working interest, which includes the work program commitment on both blocks during the first three years of the exploratory period. As of December 31, 2017, the remaining commitments in these blocks for the first exploratory period amount to US$1.2 million at our working interest.

CN-V Block Farm-in Agreement

On July 22, 2015, we signed a farm-in agreement with Wintershall for the CN-V Block in Argentina, which complements our existing acreage in the basin. Wintershall is Germany's largest oil and gas producer and a subsidiary of BASF Group. We will operate during the exploratory phase and receive a 50% working interest in the CN-V Block in exchange for having drilled one exploratory well before the end of the second quarter of 2017 and to drill another exploratory well before the end of the second exploration period, for a total of US$10 million.

The CN-V Block covers an area of approximately 117,000 acres and is located in the Neuquén Basin in southern Argentina. The block has 3D seismic coverage of 180 sq. km and is adjacent to the producing Loma Alta Sur oil field, a region and play-type well known to our team. The block includes upside potential in the developing Vaca Muerta unconventional play.

During 2017, we drilled the first exploratory well, Rio Grande Oeste 1, which resulted in the discovery of Rio Grande Oeste oil field. These investments represent the fulfilment of 50% of the commitment for the block.

Del Mosquito Block

On April 2016 the concession of the Del Mosquito expired and we relinquished the entire remaining acreage to provincial authorities. As of the date of this annual report, the approval of the abandonment plan for remediation and restoration of the block is still pending.

Oil and natural gas reserves and production

Overview

We have achieved consistent growth in oil and gas reserves from our investment activities since 2007, when we began production in the Fell Block, followed by successful acquisition, exploration and development activities in other countries in which we have a presence, including Colombia, Brazil and Peru.

Our reserves

The following table sets forth our oil and natural gas net proved reserves as of December 31, 2016, which is based on the D&M Reserves Report.

Net proved reserves As of December 31, 2017	Oil (mmbbl)	Natural gas (bcf)	Total net proved reserves (mmboe)(1)	% Oil
Net proved developed				
Colombia	21.1	-	21.1	100%
Chile	0.7	8.7	2.2	32%
Peru	9.5	-	9.5	100%
Brazil	0.1	23.8	4.0	3%
Total net proved developed	**31.4**	**32.5**	**36.8**	**85%**
Net proved undeveloped				
Colombia	44.4	-	44.4	100%
Chile	3.4	11.3	5.3	64%
Peru	9.2	-	9.2	100%
Brazil	-	-	-	-
Total net proved undeveloped (2)	**57.0**	**11.3**	**58.9**	**97%**
Total net proved (Colombia, Chile, Peru, Brazil)	**88.4**	**43.8**	**95.7**	**92%**

[(1)] We calculate one barrel of oil equivalent as six mcf of natural gas.
[(2)] We plan to put 100% of our reported 2017 year-end proved undeveloped reserves into production through activities to be implemented within five years of initial disclosure.

Changes for the year ended December 31, 2017 not including annual production, include (i) an increase of 3.8 mmboe resulting from better than expected performance from existing wells, from the Tigana and Jacana fields in the Llanos 34 Block; (ii) an increase of 3.0 mmboe resulting from the impact of higher average prices; (iii) an increase of 1.5 mmboe due to a better performance in the proved reserves in Chile and (iv) an increase of 29.0 mmboe due to extensions and discoveries from the Chiricoca, Jacamar, and Curucucu fields in the Llanos 34 Block and the Tigana and Jacana field extensions in the Llanos 34 Block. Such increase was partially offset by a decrease in reserves mainly related to a change in a previously adopted development plan and unsuccessful proved undeveloped execution in the Fell Block in Chile, resulting in a 6.0 mmboe decrease.

During the year ended December 31, 2017, we had 12.5 mmboe of our proved undeveloped reserves from December 31, 2016 converted to proved developed reserves due to development drilling in the Jacana and Tigana oil fields in the Llanos 34 Block. For further information relating to the reconciliation of our net proved reserves for the years ended December 31, 2017, 2016 and 2015, please see Table 5 included in Note 37 (unaudited) to our Consolidated Financial Statements.

Internal controls over reserves estimation process

We maintain an internal staff of petroleum engineers and geosciences professionals who work closely with our independent reserves engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserves engineers in their estimation process and who have knowledge of the specific properties under evaluation. Our Director of Development, Carlos Alberto Murut, is primarily responsible for overseeing the preparation of our reserves estimates and for the internal control over our reserves estimation. He has more than 30 years of industry experience as an E&P geologist, with broad experience in reserves assessment, field development, exploration portfolio generation and management and acquisition and divestiture opportunities evaluation. See "Item 6. Directors, Senior Management and Employees—A. Directors and senior management."

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

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

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

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

Independent reserves engineers

Reserves estimates as of December 31, 2017 for Colombia, Chile, Brazil and Peru included elsewhere in this annual report are based on the D&M Reserves Report, dated February 15, 2018 and effective as of December 31, 2017. The D&M Reserves Report, a copy of which has been filed as an exhibit to this annual report, was prepared in accordance with SEC rules, regulations, definitions and guidelines at our request in order to estimate reserves and for the areas and period indicated therein.

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

The D&M Reserves Report covered 100% of our total reserves. In connection with the preparation of the D&M Reserves Report, DeGolyer and MacNaughton prepared its own estimates of our proved reserves. In the process of the reserves evaluation, DeGolyer and MacNaughton did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of DeGolyer and MacNaughton that brought into question the validity or sufficiency of any such information or data, DeGolyer and MacNaughton did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. DeGolyer and MacNaughton independently prepared reserves estimates to conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(2) of Regulation S-X. DeGolyer and MacNaughton issued the D&M Reserves Report based upon its evaluation. D&M's primary economic assumptions in estimates included oil and gas sales prices determined according to SEC guidelines, future expenditures and other economic assumptions (including interests, royalties and taxes) as provided by us. The assumptions, data, methods and procedures used, including the percentage of our total reserves reviewed in connection with the preparation of the D&M Reserves Report were appropriate for the purpose served by such report, and DeGolyer and MacNaughton used all methods and procedures as it considered necessary under the circumstances to prepare such reports.

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

Technology used in reserves estimation

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

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

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

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

Proved undeveloped reserves

As of December 31, 2017, we had 58.9 mmboe in proved undeveloped reserves, an increase of 10.8 mmboe, or 22%, over our December 31, 2016 proved undeveloped reserves of 48.1 mmboe. Changes for the year ended December 31 2017, include (i) an increase of 28.4 mmboe in Colombia due to the Chiricoca, Jacamar and Curucucú Field discoveries in the Llanos 34 Block and the Tigana and Jacana field extensions in the Llanos 34 Block; (ii) an increase of 1.2 mmboe due to the impact of higher average oil prices partially offset by a removal of 0.6 mmboe of proved undeveloped reserves related to changes in the development plan in Colombia and (iii) a decrease in reserves of 5.9 mmboe from the Fell Block mainly related to a change in a previously adopted development plan and unsuccessful proved undeveloped executions.

During the year ended December 31, 2017, we had 12.5 mmboe of our proved undeveloped reserves from December 31, 2016 converted to proved developed reserves due to development drilling in the Jacana and Tigana oil fields in the Llanos 34 Block. See Note 37 to our Consolidated Financial Statements.

Of our 58.9 mmboe of net proved undeveloped reserves, 44.4 mmboe (75%), 5.3 mmboe (9%), and 9.2 mmboe (16%) were located in Colombia, Chile and Peru, respectively.

During 2017, we incurred approximately US$19.1 million in capital expenditures to convert such proved undeveloped reserves to proved developed reserves, of which approximately US$15.9 million, and US$3.2 million were made in Colombia and Chile, respectively.

No net proved undeveloped reserves were located in Argentina and Brazil as of December 31, 2017.

The following table shows the evolution of total net proved undeveloped ("PUD") reserves in the year ended December 31, 2017.

Total Net Proved Undeveloped ("PUD") Reserves at December 31, 2016	**48.1**
(All amounts shown in mmboe)	
Plus: Extensions, discoveries and acquisitions:	
-Colombia	28.4
-Chile	0.3
-Brazil	-
-Peru	-
Less: PUD Reserves converted to proved developed reserves:	
-Colombia	**(12.5)**
-Chile	-
-Brazil	-
Plus/less: PUD Reserves revisions and movement to/from other categories:	
-Colombia	0.6
-Chile	(5.9)
-Brazil	-
-Peru	(0.1)
Total Net Proved Undeveloped ("PUD") Reserves at December 31, 2017	**58.9**

Production, revenues and price history

The following table sets forth certain information on our production of oil and natural gas in Colombia, Chile, Brazil and Argentina for each of the years ended December 31, 2017, 2016 and 2015.

Average daily production[1] As of December 31										
				2017			2016			2015
	Colombia	Chile	Brazil	Argentina	Colombia	Chile	Brazil	Colombia	Chile	Brazil
Oil production										
Average crude oil production (bopd)	21,718	1,000	42	4	15,536	1,380	39	13,183	1,938	48
Average sales price of crude oil (US$/bbl) [3]	36.1	45.7	60.1	52.3	24.4	37.0	48.0	30.4	42.2	53.1
Natural gas										
Average natural gas production (mcfpd)	414	11,317	17,209	-	-	14,964	17,346	-	11,380	19,672
Average sales price of natural gas (US$/mcf) [3]	5.9	4.5	5.8	-	-	3.8	5.0	-	4.5	4.7
Oil and gas production cost										
Average operating cost (US$/boe)	5.6	20.3	7.8	242.6	5.4	15.8	5.8	8.8	21.0	4.4
Average royalties and Other (US$/boe)	3.2	1.4	3.2	10.0	1.4	1.1	2.8	1.8	1.5	2.6
Average production cost (US$/boe)[2]	8.8	21.7	11.0	252.6	6.7	16.9	8.5	10.6	22.5	7.1

[1] We present production figures net of interests due to others, but before deduction of royalties, as we believe that net production before royalties is more appropriate in light of our foreign operations and the attendant royalty regimes.
[2] Calculated pursuant to FASB ASC 932.
[3] Averaged realized sales price for oil does not include our Argentine blocks because our Argentine operations were not material during such periods. Averaged realized sales price for gas does not include our Argentine and Colombian blocks because our gas operations in those countries were not material during such period.

The following table sets forth certain information on our production of oil and natural gas by final product sold in Colombia, Chile, Brazil and Argentina for each of the years ended December 31, 2017, 2016 and 2015.

		2017		2016		2015
	Oil Mbbl	Gas Mmcf	Oil Mbbl	Gas Mmcf	Oil Mbbl	Gas Mmcf
Tigana oil field[1]	2,767.0	-	1,871.5	-	1,809.7	-
Jacana oil field[1]	2,566.0	-	1,188.6	-	151.3	-
Rest of Colombia	1,870.0	-	2,113.2	-	2,615.0	-
Chile	347.0	3,745.0	502.8	5,293.0	707.1	4,025.4
Brazil	15.0	5,763.0	14.0	6,314.0	17.6	7,213.0
Argentina[2]	-	-	-	-	-	-
Total	**7,565.0**	**9,508.0**	**5,690.1**	**11,607.0**	**5,300.7**	**11,238.4**

[1] The Tigana (discovered in 2013) and Jacana (discovered in 2015) oil fields in Colombia are separately included in the table above as those oil fields individually contain more than 15% of our total proved reserves as of each of the years indicated above.
[2] Production from CN-V Block is related to Río Grande Oeste x1 well. Declaration of commerciality is still pending as of December 31, 2017.

Drilling activities

The following table sets forth the exploratory wells we drilled as operators during the years ended December 31, 2017, 2016 and 2015.

	Exploratory wells[1] As of December 31									
				2017			2016			2015
	Colombia	Chile	Brazil	Argentina	Colombia	Chile	Brazil	Colombia	Chile	Brazil
Productive[2]										
Gross	5.0	1.0	-	1.0	3.0	-	-	3.0	-	-
Net	2.3	1.0	-	0.5	1.4	-	-	1.4	-	-
Dry[3]										
Gross	1.0	-	1.0	-	-	-	-	1.0	-	-
Net	0.5	-	1.0	-	-	-	-	0.5	-	-
Total										
Gross	6.0	1.0	1.0	1.0	3.0	-	-	4.0	-	-
Net	2.8	1.0	1.0	0.5	1.4	-	-	1.9	-	-

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

The following table sets forth the development wells we drilled as operators during the years ended December 31, 2017, 2016 and 2015.

	Development wells[1] As of December 31									
				2017			2016			2015
	Colombia	Chile	Brazil	Argentina	Colombia	Chile	Brazil	Colombia	Chile	Brazil
Productive[2]										
Gross	17.0	1.0	-	-	3.0	1.0	-	2.0	-	-
Net	7.7	1.0	-	-	1.4	1.0	-	0.9	-	-
Dry[3]										
Gross	1.0	-	-	-	-	-	-	-	-	-
Net	0.5	-	-	-	-	-	-	-	-	-
Total										
Gross	18.0	1.0	-	-	3.0	1.0	-	2.0	-	-
Net	8.2	1.0	-	-	1.4	1.0	-	0.9	-	-

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

Developed and undeveloped acreage

The following table sets forth certain information regarding our total gross and net developed and undeveloped acreage in Colombia, Chile, Brazil and Peru as of December 31, 2017.

	Acreage[(1)] (in thousands of acres)				
	Colombia	Chile	Perú	Brazil	Argentina
Total developed acreage					
Gross	8.5	8.2	1.1	4.1	-
Net	4.4	7.7	0.8	0.4	-
Total undeveloped acreage					
Gross	239.8	799.8	1,879.9	268.9	1,855.6
Net	119.9	590.0	1,410.0	249.8	371.4
Total developed and undeveloped acreage					
Gross	248.3	808.0	1,881.0	273.0	1,855.6
Net	124.3	597.7	1,410.8	250.2	371.4

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

Productive wells

The following table sets forth our total gross and net productive wells as of February 28, 2018. Productive wells consist of producing wells and wells capable of producing, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Productive wells[(1)]				
	Colombia[(2)]	Chile	Brazil	Peru	Argentina
Oil wells					
Gross	90	47	-	-	1
Net	54.8	44	-	-	0.5
Gas wells					
Gross	2	49	6	-	-
Net	0.3	48	0.6	-	-

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

(2)We acquired Winchester and Luna in February 2012 and Cuerva in March 2012. Figures include wells drilled by Winchester, Luna and Cuerva prior to their acquisition by us.

Present activities

Our average oil and gas production in the first quarter of 2018 was 32,195 mboepd, with oil production of 27,345 mbopd and gas production of 4,850 mboepd. Of this total production, 82%, 9% and 9% were in Colombia, Chile and Brazil, respectively.

During the first quarter of 2018, we drilled and put into production three wells in Colombia in the Llanos 34 Block, as follows:

- Tigana Norte 6 development well was drilled to a total depth of 11,596 feet. A production test conducted with an electric submersible pump in the Guadalupe formation resulted in a production rate of 1,360 bopd of 14.3 degrees API, with 0.6% water cut.
- Tigana Norte 7 development well was drilled to a total depth of 12,050 feet. A production test conducted with an electric submersible pump in the Guadalupe formation resulted in a production rate of 424 bopd of 13.5 degrees API, with 15% water cut.
- Jacana 20 development well was drilled to a total depth of 11,521 feet. A production test conducted with an electric submersible pump in the Guadalupe formation resulted in a production rate of 590 bopd of 16.8 degrees API, with 17% water cut.

Additional production history is required to determine stabilized flow rates of the above mentioned wells.

Also, during the first quarter of 2018, we commenced drilling Jet 1 in the POT-T-747 block and 619-AB-1 in the POT-T-619 block exploration wells, which have been abandoned as of the date of this annual report. Jet 1 resulted in a non-commercial oil discovery, while 619-AB-1 was abandoned after logging as there was no hydrocarbon production potential. Drilling, completion and abandonment costs of these two wells amounted to approximately US$1.7 million.

Marketing and delivery commitments

Colombia

Our production in Colombia consists primarily of crude oil. Sales for the year ended December 31, 2017 were made under a long term sales agreements as described below.

Evacuation of the oil produced is structured under two types of sales: wellhead and pipeline. For wellhead sales, delivery point is at the loading station at fields. For pipeline sales, delivery point is at the uploading station that discharges to the national pipeline network. In Colombia, pipelines have minimum quality conditions that restrict access to the system. Consequently, and because we are mid to heavy oil producers, our entrance to the pipeline requires the use of diluents which are blended into our crude. For the year ended December 31, 2017, we sold 99% of our operated production directly at the wellhead.

Oil sales are structured under a price formula based on a market reference Index (Brent or Vasconia) and discounts that consider market fees, quality,

handling fees and transportation among other associated costs.
Under the Trafigura Agreement, we followed agreed priorities for the volumes to be transported through the ODL Pipeline. For the period from March 1, 2016 to September 1, 2016, Trafigura received 10,000 bopd of our production. In 2016 and 2017, the Trafigura Agreement was amended setting the current volumes to be delivered to Trafigura to 12,000 bopd until December 2018. Nonperformance of our obligations of delivery in terms, amounts and quality of the crude to Trafigura may require us to pay Trafigura's fare commitments in ODL Pipeline for the transport, dilution and download of crude, and may lead to early termination of the crude sales agreement as well as the immediate repayment of any amounts outstanding under the prepayment agreement, as well as compensation for other damages.

The evacuation strategy is aimed at developing synergies with both the client and the national systems, in order to obtain a reduction in costs and better revenues by making use of the best practices. In order to achieve this purpose, strategic alliances have been established with different agents in the transport chain in order to guarantee direct access to the national network. Such is the case of the implementation of an unloading facility in partnership with Oleoducto de Los Llanos. This unloading facility is located 42 km away from the Llanos 34 block. Therefore, a reduction in transportation costs has been gained since the distance for trucking has been reduced significantly.
If we were to lose our key customers, the loss could temporarily delay production and sale of our oil in the corresponding block. However, given the wide availability of customers for Colombian crude, we believe we could identify a substitute customer to purchase the impacted production volumes.

Chile

Our customer base in Chile is limited in number and primarily consists of ENAP and Methanex. For the year ended December 31, 2017 we sold 100% of our oil production in Chile to ENAP and 95% of our gas production to Methanex, with sales to ENAP and Methanex accounting for 10% and 9%, respectively, of our total revenues in the same period.

On April 21, 2017, we renewed our sales agreement with ENAP. As part of this agreement, ENAP has committed to purchase our oil production in the Fell Block in the amounts that we produce, subject to the limitation of available storage capacity at the Gregorio Terminal. The sales agreement provides us with the option to interrupt sales to ENAP periodically if conditions in the export markets allow for more competitive price levels. While the agreement renews automatically on an annual basis, we typically revise the agreement every year to reflect changes in the global oil market and make certain adjustments based on ENAP's expenses related to storage at the Gregorio Terminal.

Commercial conditions of the new agreement are similar to the previous one in effect. We deliver the oil we produce in the Fell Block to ENAP at the Gregorio Terminal, where ENAP assumes responsibility for the oil transferred. ENAP owns two refineries in Chile in the north central part of the country and must ship any oil from the Gregorio Terminal to these refineries unless it is consumed locally.

We signed the Methanex Gas Supply Agreement in Chile in 2009, which expired in April 30, 2017. In March 2017, we executed a new gas supply agreement with Methanex effective from May 1, 2017 to December 31, 2026. Under the agreement, Methanex commits to purchase up to 400,000 SCM/d of gas produced by us. In 2018, due to the decline in gas production, the commitment was reduced to 315,000 SCM/d. We also hold an option to deliver up to 15% above this volume.

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

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

Brazil

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

The Manati Field is developed via a PMNT-1 production platform, which is connected to the Estação Vandemir Ferreira, or EVF, gas treatment plant through an offshore and onshore pipeline with a capacity of 335.5 mmcfpd (9.5 mm3 per day). The existing pipeline connects the field's platform to the EVF gas treatment plant, which is owned by the field's current concession holders. During 2015, in order to improve the field gas recovery and production, Manatì's consortium built an onshore compression plant that started operating in August 2015, which allowed us to classify all existing proved undeveloped reserves as proved developed as of December 31, 2016. The BCAM-40 Concession, which includes the Manati Field, also benefits from the advantages of Petrobras' size. As the largest onshore and offshore operator in Brazil, Petrobras has the ability to mobilize the resources necessary to support its activities in the concession.

The condensate produced in the Manati Field is subject to a condensate purchase agreement with Petrobras, pursuant to which Petrobras has committed to purchase all of our condensate production in the Manati Field, but only in the amounts that we produce, without any minimum or maximum deliverable commitment from us. The agreement is valid through December 31, 2018, and can be renewed upon an amendment signed by Petrobras and the seller.

Peru

In Peru, oil production is generally traded on a free market basis and commercial conditions generally follow international markers, normally WTI and Brent. As per the Joint Operating Agreement executed with Petroperu, Petroperu has the first option to acquire oil produced by us in the Morona Block by matching any offer received by third parties regarding such production.

Future production in the Morona Block is expected to be transported through the existing North Peruvian Pipeline. This transportation system is owned and operated by Petroperu, and regulated and supervised by OSINERGMIN, the regulatory body in the hydrocarbons sector. Transportation rates are negotiated with Petroperu. However, if an agreement cannot be reached between Petroperu and us, transportation rates will be determined by OSINERGMIN. The North Peruvian pipeline was out of service in 2017 due to technical issues. The Peruvian government has enacted a law declaring that the pipeline's operation is a matter of national interest, and is implementing a maintenance program accordingly. See "Item 3. Risk factors—Risks relating to our business—Our inability to access needed equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets and generate significant incremental costs or delays in our oil and natural gas production."

Argentina

The crude produced in our CN-V block in Mendoza is sold to YPF SA ("YPF") under short term agreements that can be renewed by the parties. The Argentine crude market standard has been to transact under short term agreements over the past years, making our agreement with YPF aligned to outstanding domestic market practices. YPF additionally provides us with receipt and treatment services for a fee.

Significant Agreements

Colombia

E&P Contracts

We have entered into E&P Contracts granting us the right to explore and operate, as well as working interests in six blocks in Colombia. These E&P Contracts are generally divided into two periods: (1) the exploration period, which may be subdivided into various exploration phases and (2) the exploitation period, determined on a per-area basis and beginning on the date we declare an area to be commercially viable. Commercial viability is determined upon the completion of a specified evaluation program or as otherwise agreed by the parties to the relevant E&P Contract. The exploitation period for an area may be extended until such time as such area is no longer commercially viable and certain other conditions are met. Pursuant to our E&P Contracts, we are required, as are all oil and gas companies undertaking exploratory and production activities in Colombia, to pay a royalty to the Colombian government based on our production of hydrocarbons, as of the time a field begins to produce. Under Law 756 of 2002, as modified by Law 1530 of 2012, the royalties we must pay in connection with our production of light and medium oil are calculated on a field-by-field basis. See Note 32(a) to our Consolidated Financial Statements. Additionally, in the event that an exploitation area has produced amounts in excess of an aggregate amount established in the E&P Contract governing such area, the ANH is entitled to receive a "windfall profit," to be paid periodically, calculated pursuant to such E&P Contract.

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

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

Llanos 34 Block E&P Contract . Pursuant to an E&P Contract between Unión Temporal Llanos 34 (a consortium between Ramshorn and Winchester Oil and Gas - now GeoPark Colombia SAS) and the ANH that became effective as of March 13, 2009 ("Llanos 34 Block E&P Contract"), Unión Temporal Llanos 34 was granted the right to explore and operate the Llanos 34 Block, and we and Ramshorn were granted a 40% and a 60% working interest, respectively, in the Llanos 34 Block. We were also granted the right to operate the Llanos 34 Block. On December 16, 2009, Winchester Oil and Gas (now GeoPark Colombia) entered into a joint operating agreement with Ramshorn and P1 Energy with respect to our operations in the block. As of the date of this annual report, the members of the Union Temporal Llanos 34 are GeoPark Colombia SAS with

45%, and Parex Verano Limited with 55% working interest.

We are currently in an additional exploration period (the contract provides for two optional exploratory phases of 18 months each, in which the operator carries out exploratory activities in order to retain areas to explore) of the Llanos 34 Block E&P Contract with an exploitation program in execution over certain areas. The contract also provides for a six-year exploration period consisting of two three-year phases. It also provides for a 24-year exploitation period for each commercial area, which begins on the date on which such area is declared commercially viable. The exploitation period may be extended for periods of up to 10 years at a time until such time as the area is no longer commercially viable and certain conditions are met. We have presented evaluation programs to the ANH for the Tilo Field. We presented the declaration of commerciality of Max, Túa, Tarotaro, Tigana, Jacana and Chachalaca, respectively.

Pursuant to the Llanos 34 Block E&P Contract and applicable law, we are required to pay a royalty to the ANH based on hydrocarbons produced in the Llanos 34 Block. See Note 32(a) to our Consolidated Financial Statements. Additionally, we are required to pay a subsoil use fee to the ANH. ANH also has the right to receive an additional fee when prices for oil or gas, as the case may be, exceed the prices set forth in the Llanos 34 Block E&P Contract. The ANH also has an additional economic right equivalent to 1% of production, net of royalties.

In accordance with the Llanos 34 Block operation contract, when the accumulated production of each field, including the royalties' volume, exceeds 5 million barrels and the WTI exceeds a defined base price, the Company should deliver to ANH a share of the production net of royalties in accordance with an established formula. See Note 32(a) to our Consolidated Financial Statements.

Winchester and Luna Stock Purchase Agreement

Pursuant to the stock purchase agreement entered into on February 10, 2012 (the "Winchester Stock Purchase Agreement"), we agreed to pay the Sellers a total consideration of US$30.0 million, adjusted for working capital. Additionally, under the terms of the Winchester Stock Purchase Agreement, we are obligated to make certain payments to the Sellers based on the production and sale of hydrocarbons discovered by exploration wells drilled after October 25, 2011. Once the maximum earn-out amount is reached, we pay the Sellers quarterly overriding royalties in an amount equal to 4% of our net revenues from any new discoveries of oil. For the year ended December 31, 2017, we accrued and paid US$11.4 million and US$10.0 million with regards to this agreement.

Trafigura offtake and prepayment agreement

In December 2015, we entered into an offtake and prepayment agreement with Trafigura. The agreement provides that we sell and deliver a portion of our Colombian crude oil production to Trafigura. This benefits us by (i) improving crude oil sales prices; (ii) improving operating netbacks by reducing transportation costs; (iii) simplifying logistics and reducing risks; and (iv) improving working capital. Pricing is determined at future spot market prices, net of transportation costs. The agreement has given us access to funding up to US$100 million from Trafigura, subject to applicable volumes corresponding to the terms of the agreement, in the form of prepaid future oil sales. Funds committed by Trafigura will be made available to us upon request and will be repaid by us through future oil deliveries over the period of the contract, until December 31, 2018, with a 6-month grace period.

During 2016 and 2017 we executed successive amendments to the Trafigura offtake and prepayment agreement which increased volumes delivered, improved pricing and extended the availability period for funding.

Chile

CEOPs

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

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

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

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

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

TDF Blocks CEOPs . After an international bidding process led by ENAP and the Chilean Ministry of Energy, in March and April, 2012, we, together with ENAP, signed 3 new CEOPs for the Isla Norte, Campanario and Flamenco Blocks, all of them located in Tierra del Fuego ("TDF"), Magallanes region. Our working interest is 60% in Isla Norte and 50% in Campanario and Flamenco Blocks. The CEOPs have a term of 32 years, with an initial exploration phase which last for 7 years, including a first exploration period of 3 years in which we are committed to developing several exploration activities including 1,500 square kilometers of 3D seismic registration, and the drilling of 21 exploratory wells.

The hydrocarbon discoveries opened up an exploitation phase that lasts up to 32 years. We discovered hydrocarbon fields in the 3 blocks, starting 2013 in the Flamenco Block, and in 2014 in both Campanario and Isla Norte Blocks. The CEOPs provide us with a right to receive a remuneration payable by means of a fraction of the production sold, which in the TDF Blocks is based on a formula depending on the recovery of the total accumulated expenses incurred (capital expenditure plus operational expenditure plus administrative and general expenses). While the recovery factor is less than 1.0, the remuneration is 95% of the hydrocarbons produced, either oil or gas. If the recovery factor surpasses 1.0, a formula applies reducing gradually the remuneration fraction to a minimum of 75% when the recovery factor is 2.5 times the total accumulated expenses.

Brazil

Rio das Contas Quota Purchase Agreement

Pursuant to the Rio das Contas Quota Purchase Agreement we entered into on May 14, 2013, we agreed to acquire from Panoro all of the quotas issued by Rio das Contas for a purchase price of US$140 million (subject to working capital adjustments at closing and further earn-out payments, if any) upon satisfaction of certain conditions. With respect to the earn-out payments, the Rio das Contas Quota Purchase Agreement provides that during the calendar periods beginning on January 1, 2013 and ending as late as December 31, 2017, we will make annual earn-out payments to Panoro in an amount equal to 45% of "net cash flow," calculated as EBITDA less the aggregate of capital expenditures and corporate income taxes, with respect to the BCAM-40 Concession of any amounts in excess of US$25.0 million, up to a maximum cumulative earn-out amount of US$20.0 million in a five-year period. Once the maximum earn-out amount is reached or the five-year period has elapsed, no further earn-out amounts will be payable. For the year ended December 31, 2017, there were no earn-out payments with regards to this agreement.

We financed our Rio das Contas acquisition in part through our Brazilian subsidiary's entrance into a US$70.5 million credit facility (the "Rio das Contas Credit Facility") with Itaú BBA International plc, which is secured by the benefits we receive under the Purchase and Sale Agreement for Natural Gas with Petrobras. See "Item 5. Operating and Financial Review and Prospects—B. Liquidity and capital resources—Indebtedness—Rio das Contas Credit Facility." The loan was fully repaid in September 2017.

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

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

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

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

A concessionaire is required to pay to the Brazilian government the following:
- a license fee;
- rent for the occupation or retention of areas;
- a special participation fee;
- royalties; and
- taxes.

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

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

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

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

Under the BCAM-40 Concession Agreement, the ANP is entitled to a monthly royalty payment equal to 7.5% of the production of oil and natural gas in the concession area. In addition, in case the special participation fee of 10% shall be applicable for a field in any quarter of the calendar year, the concessionaire is obliged to make qualified research and development investments equivalent to one percent of the field's gross revenue. Area retention payments are also applicable under the concession agreement. We acquired Rio das Contas' 10% participation interest in the BCAM-40 Concession on March 31, 2014.

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

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

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

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

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

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

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

Peru
Morona Block
On October 1, 2014, we entered into an agreement with Petroperu to acquire an interest in and operate the Morona Block, located in Northern Peru. We will assume a 75% working interest of the Morona Block, with Petroperu retaining a 25% working interest. On December 1, 2016, through Supreme Decree N° 031-2016-MEN the Peruvian government approved the amendment to the License Contract of Block 64 (Morona Block) appointing GeoPark as operator and holder of 75% of the Contract.

In Peru, there is a 5-20% sliding scale royalty rate, depending on production levels. Production less than 5,000 bopd is assessed at a royalty rate of 5%. For production between 5,000 and 100,000 bopd there is a linear sliding scale between 5% and 20%. Production over 100,000 bopd has a flat royalty of 20%.

See "Item 4. Information on the Company—B. Business Overview—Our operations—Operations in Peru—Morona Block."

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

We are bound to pursue specific minimum work or investment commitments during each of the subperiods of each exploration permit. Such exploration works are valued in work units assigned to each particular type of work under the applicable bidding conditions.
Work and investment programs for the permits are required to be assured by issuing a performance bond for the value of the committed work plan.

Under the terms of our exploration permits and concession agreements, we are entitled to our proportionate share of the hydrocarbons production lifted from each block. The Province of Mendoza's state owned company, EMESA, has a 10% carried interest in each of the Puelen and Sierra del Nevado permits and any future exploitation concessions, while there is no governmental participation in the CN-V Block. During the term of our exploration permits, we are also required, under Argentine law, to pay a 15% royalty to the province on both oil and gas sales. In case we progress to an exploitation concession, the applicable royalty rate will reduce to a 12% royalty. We also pay annual surface rental fees established under Hydrocarbons Law 17,319 ("Hydrocarbons Law") and Resolution 588/98 of the Argentine Secretariat of Energy and Decree 1454/2007, and certain landowner fees.

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

Our Argentine exploration permits are governed by the laws of Argentina and the resolution of any disputes must be sought in the Mendoza Provincial Courts. If and when we make a commercial discovery in one or more of our exploration permits, we will have the right to request and obtain an exploitation concession to produce hydrocarbons in the block for 25 years, with an optional extension of up to 10 years. We also receive the right to be granted a 35-year oil transport concession to build and make use of pipelines or other transport facilities beyond the boundaries of the concession.

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

Pluspetrol Asset Purchase Agreement

Pursuant to the APA that we entered into on December 18, 2017 with Pluspetrol, we agreed to acquire a 100% working interest and operatorship of the Aguada Baguales, El Porvenir and Puesto Touquet blocks in Argentina for a total consideration of $52 million. The blocks include estimated oil and gas production of 2,700 boepd (70% light oil and 30% gas), 137,000 acres well-positioned in the Neuquen Basin and production facilities, including hydrocarbons treatment, storage, and delivery infrastructure.

We paid the consideration using proceeds from the offering of the Notes due 2024. The acquisition of the blocks closed on March 27, 2018.

Agreements with LGI

LGI Colombia Agreements

In December 2012, we agreed with LGI to extend our strategic partnership to build a portfolio of upstream oil and gas assets throughout Latin America. On December 18, 2012, LGI agreed to acquire a 20% equity interest in GeoPark Colombia SAS by making a US$14.9 million capital contribution and a US$4.9 million loan to GeoPark Colombia SAS and miscellaneous reimbursements. Concurrently, we entered into a shareholders' agreement with LGI (the "LGI Colombia Shareholders' Agreement") setting forth LGI's and our respective obligations in connection with LGI's investment in our Colombian oil and gas business through GeoPark Colombia SAS. Furthermore, LGI and Winchester (now GeoPark Colombia SAS) entered into a loan agreement, whereby, upon the closing of LGI's subscription of shares in GeoPark Colombia SAS, LGI granted a credit line (of which US$4.9 million was drawn at closing) to Winchester of up to US$12.0 million, to be used for the acquisition, development and operation of oil and gas assets in Colombia. Further, on January 8, 2014, following an internal corporate reorganization of our Colombian operations, GeoPark Colombia Coöperatie U.A. and GeoPark Latin America entered into a new members' agreement with LGI, or the LGI Colombia Members' Agreement, that sets out substantially similar rights and obligations to the LGI Colombia Shareholders' Agreement in respect of our oil and gas business through GeoPark Colombia SAS only. We refer to the LGI Colombia Shareholders' Agreement and the LGI Colombia Members' Agreement collectively as the LGI Colombia Agreements.

Under the LGI Colombia Agreements, LGI agreed to assume its share of the existing debt of GeoPark Colombia SAS and to provide additional funding to cover LGI's share of required future investments in Colombia through GeoPark Colombia SAS. In addition, we can earn back up to 12% additional equity interests in GeoPark Colombia depending on the success of our Colombian operations.

Currently, GeoPark Colombia Coöperatie has four directors, out of which one Director is elected by LGI. The LGI Colombia Agreements require the consent of LGI or the LGI-appointed director for GeoPark Colombia SAS to take certain actions, including, among others:

- making any decision to terminate or permanently or indefinitely suspend operations in or surrender our blocks in Colombia (other than as required under the terms of the relevant concessions for such blocks);
- creating of a security interest over our blocks in Colombia;
- approving of GeoPark Colombia's annual budget and work programs and the mechanisms for funding any such budget or program;
- entering into of any borrowings other than those provided in an approved

budget or incurred in the ordinary course of business to finance working capital needs;

- granting any guarantee or indemnity to secure liabilities of parties other than those of our Colombian subsidiaries;
- changing the dividend, voting or other rights that would give preference to or discriminate against the shareholders of GeoPark Colombia;
- entering into certain related party transactions;
- paying dividends from GeoPark Colombia Coöperatie; and
- disposing of any material assets other than those provided for in an approved budget and work program.

We have also agreed to ensure that the board of directors and rules and management of our other subsidiaries engaged in our Colombian oil and gas business are subject to the same principlesa nd restrictions outlined above.

The LGI Colombia Agreements provide that if either we or LGI decide to sell our respective participation in GeoPark Colombia Coöperatie, the transferring party must make an offer to sell its participation to the other party before selling those shares to a third party. In addition, any sale to a third party is subject to tag-along and drag-along rights, and the non-transferring party has the right to object to a sale to the third-party if it considers such third-party to be not of a good reputation or one of our direct competitors.

Under the LGI Colombia Agreements, we have agreed, along with LGI, to vote or otherwise cause GeoPark Colombia SAS to declare dividends only after allowing for retentions for approved work programs and budgets and capital adequacy requirements of GeoPark Colombia Coöperatie, working capital requirements, banking covenants associated with any loan entered into by GeoPark Colombia Coöperatie and its subsidiary. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—LGI, our strategic partner in Chile and Colombia, may not consent to our taking certain actions or may eventually decide to sell its interest in our Chilean and Colombian operations to a third party."

LGI Chile Shareholders' Agreements

In 2010, we formed a strategic partnership with LGI to jointly acquire and develop upstream oil and gas projects in Latin America. In 2011, LGI acquired a 20% equity interest in GeoPark Chile and a 14% equity interest in GeoPark TdF, for a total consideration of US$148.0 million, plus additional equity funding of US$18.0 million over the following three years. On May 20, 2011, in connection with LGI's investment in GeoPark Chile, we entered into a shareholders' agreement with LGI (as amended on July 4, 2011 and October 4, 2011, the "GeoPark Chile Shareholders' Agreement") and a subscription agreement (as amended on July 4, 2011 and October 4, 2011), On October 2011, in connection with LGI's investment in GeoPark TdF, we entered into a shareholder´s agreement with LGI (the "GeoPark TdF Shareholders Agreement", and together with the GeoPark Chile Shareholders' Agreement, the "LGI Chile Shareholders' Agreements"), setting forth LGI's and our respective rights and obligations in connection with LGI's investment in our Chilean oil and gas business.

The respective boards of each of GeoPark Chile and GeoPark TdF supervise their day-to-day operations. Each of these boards has four directors. As long as LGI holds at least 5% of the voting shares of GeoPark Chile, LGI has the right to elect one director and such director's alternate, and the remaining directors, and alternates, are elected by us. As long as LGI holds at least 5% of the voting shares of GeoPark TdF, LGI has the right to elect one director and such director's alternate, and the remaining directors, and alternates, are elected by GeoPark Chile.

The LGI Chile Shareholders' Agreements require the consent of LGI or the LGI appointed director in order for GeoPark Chile and GeoPark TdF, as the case may be, to take certain actions, including, among others:

- making any decision to terminate or permanently or indefinitely suspend operations in or surrender our blocks in Chile (other than as required under the terms of the relevant CEOP for such blocks or required by law);
- selling our blocks in Chile to our affiliates;
- any change to the dividend, voting or other rights that would give preference to or discriminate against the shareholders of GeoPark Chile and GeoPark TdF;
- entering into certain related party transactions; and
- creating a security interest over our blocks in Chile (other than in connection with a financing that benefits our Chilean subsidiaries).

The LGI Chile Shareholders' Agreements provide that if LGI or either Agencia or GeoPark Chile decides to sell its shares in GeoPark Chile or GeoPark TdF, as the case may be, the transferring shareholder must make an offer to sell those shares to the other shareholder before selling those shares to a third party. In addition, any sale to a third party is subject to tag-along and drag-along rights, and the non-transferring shareholder has the right to object to a sale to the third-party if it considers such third-party to be not of a good reputation or one of our direct competitors. Under the LGI Chile Shareholders' Agreements, we and LGI have also agreed to vote our common shares or otherwise cause GeoPark Chile or GeoPark TdF, as the case may be, to declare dividends only after allowing for retentions to meet anticipated future investments, costs and obligations. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—LGI, our strategic partner in Chile and Colombia, may not consent to our taking certain actions or may eventually decide to sell its interest in our Chilean and Colombian operations to a third party."

Title to properties

In each of the countries in which we operate, the state is the exclusive owner of all hydrocarbon resources located in such country and has full authority to determine the rights, royalties or compensation to be paid by private investors for the exploration or production of any hydrocarbon reserves. In Chile, the Republic of Chile grants such rights through a CEOP. In Colombia, the Republic of Colombia grants such rights through E&P Contracts or contracts of association. In Argentina, the Argentine Republic grants such rights through exploitation concessions. In Brazil, the Federative Republic of Brazil grants such rights pursuant to concession agreements. See "Item 3.

Key Information—D. Risk factors—Risks relating to the countries in which we operate—Oil and natural gas companies in Colombia, Chile, Brazil, Peru and Argentina do not own any of the oil and natural gas reserves in such countries." Other than as specified in this annual report, we believe that we have satisfactory rights to exploit or benefit economically from the oil and gas reserves in the blocks in which we have an interest in accordance with standards generally accepted in the international oil and gas industry. Our CEOPs, E&P Contracts, contracts of association, exploitation concessions and concession agreements are subject to customary royalty and other interests, liens under operating agreements and other burdens, restrictions and encumbrances customary in the oil and gas industry that we believe do not materially interfere with the use of or affect the carrying value of our interests. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—We are not, and may not be in the future, the sole owner or operator of all of our licensed areas and do not, and may not in the future, hold all of the working interests in certain of our licensed areas. Therefore, we may not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated and, to an extent, any non-wholly-owned, assets."

Our customers

In Colombia, our primary customer is Trafigura, and who represented 79%, of our total revenues for the year ended December 31, 2017. In Chile, our primary customers are ENAP and Methanex. As of December 31, 2017, ENAP purchased all of our oil and condensate production and Methanex purchased almost all of our natural gas production in Chile, and represented 5% and 5%, respectively, of our total revenues for the year ended December 31, 2017. In Brazil, all of our hydrocarbons in Manati are sold to Petrobras. In Peru, our primary customer may be Petroperu, has the first option to acquire the oil produced by us in the Morona Block by matching any offer received by third parties regarding such production.

Seasonality

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

However, as the Morona Block is located in a remote area, the development of the project depends on significant infrastructure being built which can be impacted by seasonal weather patterns, including rain. Since there are no roads available in the surrounding area, logistics will be performed by helicopters or barges during specific seasons of the year.

We take such seasonality into account in planning for and conducting our operations, such that the impact on our overall business is not material.

Our competition

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

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

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

Health, safety and environmental matters

General

Our operations are subject to various stringent and complex international, federal, state and local environmental, health and safety laws and regulations in the countries in which we operate. These laws and regulations govern matters including the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use and transportation of regulated materials; and human health and safety. These laws and regulations may, among other things:

- require the acquisition of various permits or other authorizations or the preparation of environmental assessments, studies or plans (such as well closure plans) before seismic or drilling activity commences;
- enjoin some or all of the operations of facilities deemed not in compliance with permits;
- restrict the types, quantities or concentration of various substances that can be released into the environment related to oil and natural gas drilling, production and transportation activities;
- require establishing and maintaining bonds, reserves or other commitments to plug and abandon wells;
- limit or prohibit seismic and drilling activities in certain locations lying within or near protected or environmentally sensitive areas;

- require preventative measures to mitigate pollution from our operations, which, if not undertaken, could subject us to substantial penalties; and
- require us to maintain a safe and healthy working environment for all employees, contractors and visitors in accordance with applicable regulations and industry best practices.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. Compliance with these laws can be costly. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Public interest in the protection of the environment continues to increase. Drilling in some areas has been opposed by certain community and environmental groups and, in other areas, has been restricted.

Climate change

Both our operations and the combustion of oil and natural gas-based products results in the emission of greenhouse gases, which may contribute to global climate change. Climate change regulation has gained momentum in recent years internationally and at the federal, regional, state and local levels. On the international level, various nations have committed to reducing their greenhouse gas emissions pursuant to the Kyoto Protocol. The Kyoto Protocol was set to expire in 2012. In late 2011, an international climate change conference in Durban, South Africa resulted in, among other things, an agreement to negotiate a new climate change regime by 2015 that would aim to cover all major greenhouse gas emitters worldwide, including the U.S., and take effect by 2020. In November and December 2012, at an international meeting held in Doha, Qatar, the Kyoto Protocol was extended by amendment until 2020. In addition, the Durban agreement to develop the protocol's successor by 2015 and implement it by 2020 was reinforced. We are committed to controlling the emission of greenhouse gases and implementing available technologies to reduce the impact caused by our operations. For example, during 2016 we began a migration plan to replace diesel with natural gas and electric generation.

Our HSE Management System

Our health, safety and environmental management plan is focused on undertaking realistic and practical programs based on recognized world practices. Our emphasis is on building key principles and company-wide ownership and then expanding programs as we continue growing. Our S.P.E.E.D. philosophy and our HSE Plan have been developed with reference to ISO 14001 for environmental management issues, OHSAS 18001 for occupational health and safety management issues, SA 8000 for social accountability and workers' rights issues and applicable World Bank Standards.

Our Environmental Policy

Our policy looks forward to meet or exceed environmental regulations in the countries in which we operate. We believe that oil and gas can be produced in an environmentally-responsible manner with proper care, understanding and management. Within our S.P.E.E.D. philosophy we have a team that is exclusively focused on securing the environmental authorizations and permits for the projects we undertake. This professional and trained team, specialized in environmental issues, is also responsible for the achievement of the environmental standards set by our Board of Directors and for training and supporting our personnel. Our senior executives, personnel in the field, visitors and contractors have also received training in proper environmental management.

Our Health and Safety Policy

We believe that the implementation of additional safety tools in our operations in 2016 has significantly contributed to control and minimizing risks in our operations. Actions taken by us included the development of a new Proactive Observation Program, HSE training, permits to work, internal audits, drills, pre-job meetings and job safety analysis, among others. As of December 31, 2017, on the last 12-month basis, our HSE development statistics workforce shows that Lost Time Injury Frequency (LTIF) was 1.14 (out of every 1,000,000 worked hours), our Total Recordable Incident Rate (TRIR) was 2.86 (out of every 1,000,000 worked hours) and we had no fatal incidents related to operations in 2017.

In 2016, we subscribed to the International Association of Oil and Gas Producers in order to align our Management System and policies with the best international standards.

Certain Bermuda law considerations

As a Bermuda exempted company, we and our Bermuda subsidiaries are subject to regulation in Bermuda. We have been designated by the BMA as a non-resident for Bermuda exchange control purposes. This designation allows us to engage in transactions in currencies other than the Bermuda dollar, and there are no restrictions on our ability to transfer funds (other than funds denominated in Bermuda dollars) in and out of Bermuda.

Under Bermuda's law, "exempted" companies are companies formed for the purpose of conducting business outside Bermuda from a principal place of business in Bermuda. As exempted companies, we and our Bermuda subsidiaries may not, without a license or consent granted by the Minister of Finance of Bermuda, participate in certain business transactions, including transactions involving Bermuda landholding rights and the carrying on of business of any kind for which we or our Bermuda subsidiaries are not licensed in Bermuda.

Insurance

We maintain insurance coverage of types and amounts that we believe to be customary and reasonable for companies of our size and with similar operations in the oil and gas industry. However, as is customary in the industry, we do not insure fully against all risks associated with our business, either because such insurance is not available or because premium costs are considered prohibitive.

Currently, our insurance program includes, among other things, construction, fire, vehicle, technical, umbrella liability, director's and officer's liability and employer's liability coverage. Our insurance includes various limits and deductibles or retentions, which must be met prior to or in conjunction with recovery. A loss not fully covered by insurance could have a materially adverse effect on our business, financial condition and results of operations. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Oil and gas operations contain a high degree of risk and we may not be fully insured against all risks we face in our business."

Industry and regulatory framework

Colombia

Regulation of the oil and gas industry

The ANH is responsible for managing all exploration lands not subject to previously existing association contracts with Ecopetrol. The ANH began offering all undeveloped and unlicensed exploration areas in the country under E&P Contracts and Technical Evaluation Agreements, or TEAs, which resulted in a significant increase in Colombian exploration activity and competition, according to the ANH. The ANH is also in charge of negotiating and executing contracts through "direct negotiation" mechanisms with attention to special conditions in the areas to be explored. The regulatory landscape in Colombia has recently changed. The regime for the ANH's contracts is set forth in Agreement 008 of 2004 and Agreement 004 of 2012. Accord 008 of 2004 issued by the Directive Council of the ANH, as repealed and replaced by Accord 004 of 2012, sets forth the necessary steps for entering into E&P Contracts with the ANH. This Agreement regulates E&P contracts entered into from May 4, 2012. E&P contracts entered into before that date are still regulated by Agreement 008 of 2004. Due to the oil price crisis of 2015, the ANH implemented transitory measures through Agreements 002, 003, 004 and 005 of 2015. On May 18, 2017, the ANH issued Agreement 002, which repealed and replaced Agreement 004 of 2012 and transitory measures adopted in 2014 and 2015. Agreement 002 of 2017 established rules for the allocation of hydrocarbon areas and adopted criteria for the exploration and exploitation of hydrocarbons owned by Colombia, including the selection of contractors, and management, execution, termination, liquidation, monitoring, control and supervision of corresponding contracts. Agreement 002 of 2017 regulates contracts entered into from May 18, 2017. E&P contracts entered into before that date are still regulated by the Agreements under which they were executed, except for any modification, addition, extension, assignment and other action related to the execution of contracts submitted by the parties to the ANH after May 18, 2017, which are regulated by Agreement 002 of 2017.

Regulatory framework

Regulation of exploration and production activities

Pursuant to Colombian law, the state is the exclusive owner of all hydrocarbon resources located in Colombia and has full authority to determine the rights, royalties or compensation to be paid by private investors for the exploration or production of any hydrocarbon reserves. The Ministry of Mines and Energy is the authority responsible for regulating all activities related to the exploration and production of hydrocarbons in Colombia.

Decree Law 1056 of 1953 (Código de Petróleos), or the Petroleum Code, establishes the general procedures and requirements that must be completed by a private investor and disclosure procedures that need to be followed during the performance of these activities.

Exploration and production activities were governed by Decree 1895 of 1973 until September 2009. Decree Law 2310 of 1974 (as complemented by Decree 743 of 1975) governed the contracts and contracting processes carried out by Ecopetrol and the rules applicable to such contracts, and also provided that Ecopetrol was responsible for administering the hydrocarbons resources in the Country. Decree 2310 of 1974 was replaced by Decree Law 1760 of 2003, but all agreements entered into by us prior to 2003 with other oil companies are still regulated by Decree 2310 of 1974.

The regime for the ANH's contracts is set forth in Agreement 008 of 2004 and Agreement 004 of 2012. Accord 008 of 2004, as repealed and replaced by Accord 004 of 2012, issued by the Directive Council of the ANH, sets forth the necessary steps for entering into E&P Contracts with the ANH. This Agreement only regulates the contracts entered into as of May 4, 2012. Prior contracts are still ruled by Agreement 008 of 2004. Due to the oil prices crisis of 2015, the ANH implemented transitory measures through Agreements 002, 003, 004 and 005 of 2015, which are still in place. The ANH is working on a new Agreement that compiles the relevant rulings in one document.

Resolution 18-1495 of 2009 establishes a series of regulations regarding hydrocarbon exploration and exploitation. In the E&P Contracts, operators are afforded access to non-contracted blocks by committing to an exploration work program. These E&P Contracts provide companies with 100% of new production, less the participation of the ANH, which participation may differ for each E&P Contract and depends on the percentage that each company has offered to the ANH in order to be granted with a block, subject to an initial royalty payment of 8% and the payment of income taxes of 33%. In addition, the Colombian government also introduced TEAs, in which companies that enter into TEAs are the only ones to have the right to explore, evaluate and select desirable exploration areas and to propose work commitments on those areas, and have a preemptive right to enter into an E&P Contract, thereby providing companies with low-cost access to larger areas for preliminary evaluation prior to committing to broader exploration programs. A preemptive right is granted to convert the TEA into an E&P Contract. Exploration activities can only be carried out by the TEA contractor.

Pursuant to Colombian law, companies are obligated to pay a percentage of their production to the ANH as royalties and an economic right as ANH's participating interest in the production. Producing fields pay royalties in accordance with the applicable royalty program at the time of the discovery.

Taxation

The Tax Statute and Law 9 of 1991 provide the primary features of the oil and gas industry's tax and exchange system in Colombia. Generally, national taxes under the general tax statute apply to all taxpayers, regardless of industry. The main taxes currently in effect—after the December 2016 tax reform discussed below—are the income tax (40% for 2017, 37% for 2018 and 33% for 2019 onwards), sales or value added tax (19%), and the tax on financial transaction (0.4%). Additional regional taxes also apply. Colombia has entered into a number of international tax treaties to avoid double taxation and prevent tax evasion in matters of income tax and net asset tax.

Decree 2080 of 2000 (amended by Decree 4800 of 2010), or the international investment regime, regulates foreign capital investment in Colombia. Resolution 8 of the board of the Colombian Central Bank, or the Exchange Statute, and its amendments contain provisions governing exchange operations. Articles 48 to 52 of Resolution 8 provide for a special exchange regime for the oil industry that removes the obligation of repayment to the foreign exchange market currency from foreign currency sales made by foreign oil companies. Such companies may not acquire foreign currency in the exchange market under any circumstances and must reinstate in the foreign exchange market the capital required in order to meet expenses in Colombian legal currency. Companies can avoid participating in this special oil and gas exchange regime, however, by informing the Colombian Central Bank, in which case they will be subject to the general exchange regime of Resolution 8 and may not be able to access the special exchange regime for a period of 10 years.

In December 2016, the Colombian Congress approved a tax reform (Law 1819 of 2016). The main aspects of the reform are summarized below.

- The enterprise contribution on equality ("CREE" for its Spanish acronym) tax is eliminated, but a carry forward of CREE receivables and losses for income tax purposes will be permitted.
- Income tax rates will be 34% plus a 6% surcharge for fiscal year 2017, 33% plus a 4% surcharge for fiscal year 2018 and 33% for fiscal year 2019 and beyond.
- A dividend tax is included on distributions from Colombian corporations for non-resident shareholders, with tax rates of 5%, for dividends which were taxed at the corporate level and 35% and then a 5% on the remaining amount for dividends which were not taxed at the corporate level.
- Grandfather rules prevent the application of the 5% dividend tax on profits obtained before fiscal year 2017. The tax rate for profits obtained before that date which were not taxed at the corporate level would be 33% instead of 35%.
- Tax losses to be carried forward up to 12 years, losses generated before 2017 are grandfathered.
- Presumptive taxable base increases to 3.5% of the net equity at the end of the prior year.
- Cross border payments withholding tax suffered modifications. The general rule on services is that there will be a 15% withholding tax, which includes management fees, even if the service is rendered form abroad. Additionally, services rendered from abroad will be subject to VAT if the beneficiary is in Colombia (for example services rendered to GeoPark Colombia from abroad would be subject to such treatment).
- The net wealth tax is still set to expire in fiscal year 2017 for corporations, but it remains unclear if its term will be extended. The tax is not enforceable for 2018, but may be enforceable in 2019 if a law is passed by the end of this year.
- IFRS is the basis for tax purposes with certain exceptions, such as:
  - Depreciation: The general rule is that the term of depreciation is determined according to IFRS, but with a depreciation percentage cap per year for tax purposes. Assets held before 2017 will be depreciated according to the previous rules.
  - Amortization: Amortization of investments in the oil and gas industry to be depleted according to the "units of production method" beginning 2028. Beginning in fiscal year 2017 and until 2027 , exploratory investments will be amortized by the straight line method in a period of 5 years. Grandfather rule was established for undepleted investments held before fiscal year 2017
- Goodwill in the acquisition of shares is no longer subject to amortization. Goodwill generated before 2017 will be subject to amortization according to the rules enforceable at the moment of generation of the goodwill, however amortization of the undepleted values as of January 1, 2017 may not take more than five years, and must be done through the straight line method.
- VAT modifications: (a) general rate increased to 19%; (b) eight month window period to credit input tax; (c) input tax, on the acquisition or importation of fixed assets may be deductible for income tax purposes, unless it is to be treated as creditable, or as part of the tax cost of the asset; and (d) sale of crude oil to refineries subject to VAT at a rate of 19%.
- Banking tax (4x1000), to become permanent.
- Benefits for the oil and gas industry: taxpayers that increase investments in exploration of new hydrocarbon reserves, incorporation of new recoverable reserves, and the addition of proven reserves, would have the right to a Tax Refund Certificate (CERT), which could be used to pay taxes administered by the Colombian Tax Office or sold in the market to other taxpayers.
- Tax may be paid according to the following two options:
  - Paying up to 50% of the amount of the tax of one fiscal year, by investing in social projects.
  - Using the value of the investment to pay 50% of the tax, during a period of 10 years in equal installments.

In either case, the investments may not be of the nature of those that constitute deductible expenses.

Chile

Regulation of the oil and gas industry

Under the Chilean Constitution, the state is the exclusive owner of all mineral and fossil substances, including hydrocarbons, regardless of who owns the land on which the reserves are located. The exploration and exploitation of hydrocarbons may be carried out by the state, companies owned by the state or private entities through administrative concessions granted by the President of Chile by Supreme Decree or CEOPs executed by the Minister of Energy. Exploitation rights granted to private companies are subject to special taxes and/or royalty payments. The hydrocarbon exploration and exploitation industry is supervised by the Chilean Ministry of Energy.

In Chile, a participant is granted rights to explore and exploit certain assets under a CEOP. If a participant breaches certain obligations under a CEOP, the participant may lose the right to exploit certain areas or may be required to return all or a portion of the awarded areas to Chile with no right of compensation. Although the government of Chile cannot unilaterally modify the rights granted in the CEOP once it is signed, exploration and exploitation are nonetheless subject to significant government regulations, such as regulations concerning the environment, tort liability, health and safety and labor.

Regulatory framework

Regulation of exploration and production activities

Oil and gas exploration and development is governed by the Political Constitution of the Republic of Chile and Decree with Law Force No 2 of 1986 of the Ministry of Mines, which set forth the revised text of the Decree Law 1089 of 1975, on CEOPS. However, the right to explore and develop fields is granted for each area under a CEOP between Chile and the relevant contractors. The CEOP establishes the legal framework for hydrocarbon activities, including, among other things, minimum investment commitments, exploration and exploitation phase durations, compensation for the private company (either in cash or in kind) and the applicable tax regime. Accordingly, all the provisions governing the exploitation and development of our Chilean operations are contained in our CEOPs and the CEOPs constitute all the licenses that we need in order to own, operate, import and export any of the equipment used in our business and to conduct our gas and petroleum operations in Chile.

Under Chilean law, the surface landowners have no property rights over the minerals found under the surface of their land. Subsurface rights do not generate any surface rights, except the right to impose legal easements or rights of way. Easements or rights of way can be individually negotiated with individual surface land owners or can be granted without the consent of the landowner through judicial process. Pursuant to the Chilean Code of Mines, a judge can permit a party to use an easement pending final adjudication and settlement of compensation for the affected landowner.

Taxation

With regard to indirect taxes on hydrocarbon exploitation, the general rule is that hydrocarbons are transferred to the contractor (its retribution under the CEOP), and those re-acquisitions from the contractor performed by Chile or its enterprises, as well as their corresponding acts, contracts and documents, are tax exempt. In addition, hydrocarbon exports by the contractor are also tax exempt. With regard to income taxes, as provided by article 5 of Decree Law No. 1,089, the contractor is subject either to a single tax calculated on its retribution, equal to 50% of such retribution, or to the general income tax regime established in the Income Tax Law (Decree Law No. 824 of 1974), in force at the time of the execution of the public deed which contains CEOPs, terms of which will be applicable and invariable throughout the duration of the contract. Income in Chile is subject to corporate tax on an accrual basis and has a current rate of 25.5% for fiscal year 2017. The applicable and invariable corporate income tax rates of our CEOPs range between 15% and 18.5%, as follows: the Fell Block is subject to a rate of 15%, the Tranquilo Block is subject to a rate of 17% and the Flamenco, Isla Norte and Campanario Blocks are subject to a rate of 18.5% for the income accrued or received during 2012 and 17% for the income accrued or received during 2013 and onward. Dividends or profits distributed to the foreign shareholders of the contractors are subject to 35% Additional Withholding Tax with a tax credit for the corporate income tax paid by the contractor. With regard to the value added tax, contractors may obtain as a refund the value added tax (which is 19% according to the Sales and Services Tax Law contained in Decree Law No. 825 of 1974) supported or paid on the import or purchase of goods or services used in connection with the exploration and exploitation activities. The applicable tax regime for each CEOP remains unchanged throughout the duration of the CEOP.

The Chilean Congress approved a reform to the income tax law in September 2014 which was amended in February 2016. Under this reform the income tax rate will increase from 20% in 2013 to: 21% in 2014, 22.5% in 2015, 24% in 2016, 25.5% in 2017 and 27% in 2018. The operating subsidiaries that we control in Chile, which are GeoPark TdF S.A., GeoPark Fell S.p.A. and GeoPark Magallanes Limitada, are not affected by the income tax reform mentioned since they are covered by the tax treatment established in the CEOPs. The above has been confirmed by the Chilean IRS through ruling N°2478/2016.

Brazil

Regulation of the oil and gas industry

Article 177 of the Brazilian Federal Constitution of 1988 provides for the Federal Government's monopoly over the prospecting and exploration of oil, natural gas resources and other fluid hydrocarbon deposits, as well as over the refining, importation, exportation and sea or pipeline transportation of crude oil and natural gas. Initially, paragraph one of article 177 barred the assignment or concession of any kind of involvement in the exploration of oil or natural gas deposits to private industry. On November 9, 1995, however, Constitutional Amendment Number 9 altered paragraph one of article 177 so as to allow private or state-owned companies to engage in the exploration and production of oil and natural gas, subject to the conditions to be set forth by legislation.

Regulatory framework

Pricing policy

Until the enactment of the Brazilian Petroleum Law, the Brazilian government regulated all aspects of the pricing of oil and oil products in Brazil, from the cost of oil imported for use in refineries to the price of refined oil products charged to the consumer. Under the rules adopted following the Brazilian Petroleum Law, the Brazilian government changed its price regulation policies. Under these regulations, the Brazilian government: (1) introduced a new methodology for determining the price of oil products designed to track prevailing international prices denominated in U.S. dollars, and (2) gradually eliminated controls on wholesale prices.

Concessions

In addition to opening the Brazilian oil and natural gas industry to private investment, the Brazilian Petroleum Law created new institutions, including the ANP, to regulate and control activities in the sector. As part of this mandate, the ANP is responsible for licensing concession rights for the exploration, development and production of oil and natural gas in Brazil's sedimentary basins through a transparent and competitive bidding process. The ANP has conducted 14 bidding rounds for exploration concessions from 1999 through 2017. Our PN-T-597 is still subject to the entry into the concession agreement. See "—Our operations—Operations in Brazil" and "Item 3. Key information—D. Risk factors—Risks relating to our business—The PN-T-597 concession is subject to an injunction and may not close" for more information.

Taxation

The Brazilian Petroleum Law introduced significant modifications and benefits to the taxation of oil and natural gas activities. The main component of petroleum taxation is the government take, comprised of license fees, fees payable in connection with the occupation or title of areas, royalties and a special participation fee. The introduction of the Brazilian Petroleum Law presents certain tax benefits primarily with respect to indirect taxes. Such indirect taxes are very complex and can add significantly to project costs. Direct taxes are mainly corporate income tax and social contribution on net profit.

Government take. With the effectiveness of the Brazilian Petroleum Law and the regulations promulgated by the ANP, concessionaires are required to pay the Brazilian federal government the following:

- license fees;
- rent for the occupation or retention of areas;
- special participation fee; and
- royalties on production.

The minimum value of the license fees is established in the bidding rules for the concessions, and the amount is based on the assessment of the potential, as conducted by the ANP. The license fees must be paid upon the execution of the concession contract. Additionally, concessionaires are required to pay a rental fee to landowners varying from 0.5% to 1.0% of the respective hydrocarbon production.

The special participation fee is an extraordinary charge that concessionaires must pay in the event of obtaining high production volumes and/or profitability from oil fields, according to criteria established by applicable regulation, and is payable on a quarterly basis for each field from the date on which extraordinary production occurs. This participation rate, whenever due, may reach up to 40% of net revenues depending on (i) volume of production and (ii) whether the block is onshore, shallow water or deep water. Under the Brazilian Petroleum Law and applicable regulations issued by the ANP, the special participation fee is calculated based upon quarterly net revenues of each field, which consist of gross revenues calculated using reference prices published by the ANP (reflecting international prices and the exchange rate for the period) less: royalties paid; investment in exploration; operational costs; and depreciation adjustments and applicable taxes.

The ANP is responsible for determining monthly minimum prices for petroleum produced in concessions for purposes of royalties payable with respect to production. Royalties generally correspond to a percentage ranging between 5% and 10% applied to reference prices for oil or natural gas, as established in the relevant bidding guidelines (edital de licitação) and concession agreement. In determining the percentage of royalties applicable to a particular concession, the ANP takes into consideration, among other factors, the geological risks involved and the production levels expected.

Relevant Tax Aspects on Upstream Activities . The special customs regime for goods to be used in the oil and gas activities in Brazil, REPETRO, aims primarily at reducing the tax burden on companies involved in exploring and extracting oil and natural gas, through the total suspension of federal taxes due on the importation of equipment (platforms, subsea equipment, among others), under leasing agreements, subject to the compliance with applicable legal requirements. The period in which the goods are allowed to remain in Brazil under the REPETRO regime may vary depending on the importer, but usually corresponds to the duration of the contract executed between the Brazilian company and the foreign entity, or the period for which the company was authorized to exploit or produce oil and gas.

In 2007, the legislation regarding the State Value Added Tax—ICMS imposed taxation on the import of equipment into Brazil under the REPETRO regime was significantly changed by ICMS Convention No. 130/2007. This regulation allows each State to grant the ICMS tax calculation basis reduction (generating a tax burden of 7.5% with the recoverability of credits or 3%, without the recoverability of credits) for goods purchased under the REPETRO regime for the production phase and the total exemption or ICMS tax calculation basis reduction (generating a tax burden of 1.5%, without the recoverability of credits) for the exploration phase. In order to be in force, the ICMS Convention No. 130/07 must be included in each state's legislation.

For example, currently, based on Convention No. 130/2007, the state of Rio de Janeiro grants tax calculation basis reduction for the exploitation (generating a tax burden of 7.5%, with the recoverability of credits or 3%, without the recoverability of credits) and production of oil and gas (generating a tax burden of 1.5%, without the recoverability of credits). For production activities, the legislation previously granted an exemption of ICMS, which was changed to a tax calculation basis reduction, according to Resolution Sefaz No. 631, dated May 14, 2013. Taxpayers, however, have challenged this change and received favorable decisions in court in order to avoid collecting ICMS on REPETRO imports as, according to STF (Supreme Court of Justice), the temporary imports on REPETRO do not constitute an ICMS triggering event.

It is important to mention that before the enactment of the Convention No. 130/2007, the State of Rio de Janeiro has attempted to impose ICMS on production activities, based on State Law No. 4,117, dated June, 27, 2003, which was regulated by Decree No. 34,761, dated February 3, 2004, and was subsequently suspended by Decree No. 34,783 of February 4, 2004 for an undetermined period of time. This legislation has been revoked in 2015 when Rio de Janeiro State created Law No. 7,183/2015 aiming to collect ICMS on the extraction of oil and Law No. 7,182/2015 creating a new fee per barrel of oil produced in the state. The constitutionality of these laws is currently being challenged by taxpayers. It is important to highlight that, while such legislation applies for oil fields operated in the State of Rio de Janeiro, legislation may vary in other states.

Pursuant to the Brazilian Petroleum Law and subsequent legislation, the federal government enacted Law No. 10,336/01, to impose the Contribution for Intervention in the Economic Sector, or CIDE, an excise tax payable by producers, blenders and importers on transactions with some oil and fuel products, which is imposed at a flat rate based on the specific quantities of each product. Currently, the CIDE rates are zero, based on Decree No. 7,764/2012.

Brazil has enacted a corporate tax reform, Law 12.973 of 13 May 2014. On upstream operations, as from 2015 fiscal year, the new tax law may generate timing effects for income tax purposes on the deduction of pre-operational costs as well as depreciation of fixed assets and amortization of intangibles. The new law imposes restrictions for the tax deduction of goodwill arising from in-house operations and brings several changes to the Brazilian CFC rules.

Peru

Regulation of the oil and gas industry

The hydrocarbons activities in Peru are mainly regulated by the General Hydrocarbons Law (Law 26,221), and several regulations enacted in order to develop the provisions included in such law.

According to the Hydrocarbons Law, oil and gas exploration and production activities are carried out under license or service contracts granted by the government. Under a license contract, the investor pays a royalty, whereas under a service contract, the government pays remuneration to the contractor. As stated by the Peruvian Constitution and the Organic Law for Hydrocarbons, a license contract does not imply a transfer or lease of property over the area of exploration or exploitation. By virtue of the license contract, the contractor acquires the authorization to explore or to exploit hydrocarbons in a determined area, and Perupetro (the entity that holds the Peruvian state interest) transfers the property right in the extracted hydrocarbons to the contractor, who must pay a royalty to the state.

Regulatory framework

License and service contracts are approved by a supreme decree issued by the Peruvian Ministry of Economy and Finance, and the Peruvian Ministry of Energy and Mining, and can only be modified by a written agreement signed by the parties. Before initiating any negotiation, every oil and gas company must be duly qualified by Perupetro, in order to determine if it fulfills all the requirements needed to develop exploration and production activities under the contract form requirements mentioned above.
License and services agreements may be granted for just an exploitation stage -when a commercial discovery has been made- or for an exploration and exploitation stage –when such discovery has not been made yet. In this case, the exploration phase will last no more than 7 years, counted from the effective date of the contract (60 days after the signing date). This term can be divided into several periods as agreed in the contract, and all of them with a minimum work obligation that should be fulfilled by a contractor in order to access the next exploration period. The exploration phase will last until a declaration of commercial discovery is made by the contractor. The exploitation phase will last from the date of such declaration until 30 years from the date of the contract.

The Ministry of Energy and Mines may exceptionally authorize an extension of three years for the exploration stage, if the contractor has fulfilled with the minimum work program established in the contract, and also commits to fulfill an additional work program that justifies such extension. The contractor shall be responsible for providing the technical and economic resources required for the execution of the operations of this phase.

The Peruvian regulations also established the roles of the Peruvian government agencies that regulate, promote and supervise the oil and gas industry, including the Ministry of Energy and Mines, Perupetro and OSINERGMIN.

Taxation

The fiscal regime that applies in Peru to the oil and gas industry consists of a combination of corporate income tax, royalties and other levies.
In general terms, oil and gas companies are subject to the general corporate income tax regime that is stabilized in the applicable regime on the date of subscription of the original License Agreement (due to a tax stability contract); nevertheless, there are certain special tax provisions for the oil and gas sector. Resident companies (incorporated in Peru), are subject to income tax on their worldwide taxable income. Branches and permanent establishments of foreign companies that are located in Peru and non-resident entities are taxed on Peruvian source income only.

With respect to the Morona Agreement, in which we take part, the applicable income tax stabilized regime is from 1995, which is the year of subscription of the original License Agreement. The income tax rate in 1995 was 30% and there was no withholding income tax for dividends. Additionally, in 1995 it was stated that the income tax should not be lower than 2% of the net assets of the Company (the "Minimum Income Tax"). The Minimum Income Tax was later declared unconstitutional, which is why, even when there was a tax stability contract, the Minimum Income Tax has been understood as not applicable or enforceable.

Taxable income is generally computed by reducing gross revenue by cost of goods sold and all expenses necessary to produce the income or maintain the source of income. Certain types of revenue, however, must be computed as specified in the tax law and some expenses are not fully deductible for tax purposes. Business transactions must be recorded in legally authorized accounting records that are in full compliance with the International Accounting Standards (IAS). Contractors in a license or services contract for the exploration or exploitation of hydrocarbons (Peruvian corporations and branches) are entitled to keep their accounting records in foreign currency, but taxes must be paid in Peruvian Nuevos Soles ("PEN").

Any investments in a contract area that did not reach the commercial extraction stage and that were totally released, can be accumulated with the same type of investments made in another contract area that has reached the stage of commercial extraction.

These investments are amortized in accordance with the amortization method chosen by the contractor. If the contractor has entered into a single contract, the accumulated investments are charged as a loss against the results of the contract for the year of total release of the area for any contract that did not reach the commercial extraction stage, with the exception of investments consisting of buildings, power installations, camps, means of communication, equipment and other goods that the contractor keeps or recovers to use in the same operations or in other operations of a different nature.

The contractor determines the tax base and the amount of the tax, separately and for each contract. If the contractor carries out related activities (i.e., activities related to oil and gas, but not carried out under the terms of the contract) or other activities (i.e., activities not related to oil and gas), the contractor is obligated to determine the tax base and the amount of tax, separately, and for each activity. The corresponding tax is determined based on the income tax provisions that apply in each case (subject to the tax stability provisions for contract activities and based on the regular regime for the related activities or other activities). The total income tax amount that the contractor must pay is the sum of the amounts calculated for each contract, for both the related activities and for the other activities. The forms to be used for tax statements and payments are determined by the tax administration.

If the contractor has more than one contract, it may offset the tax losses generated by one or more contracts against the profits resulting from other contracts or related activities. Moreover, the tax losses resulting from related activities may be offset against the profits from one or more contracts.
It is possible to choose the allocation of tax losses to one or more of the contracts or related activities that have generated the profits, provided that the losses are depleted or compensated to the limit of the profits available. This means that if there is another contract or related activity, the taxpayer can continue compensating tax losses until they are completely offset. A contractor with tax losses from one or more contracts or related activities may not offset them against profits generated by the other activities. Furthermore, in no case may tax losses generated by the other activities be offset against the profits resulting from the contracts or the related activities.

During the exploration phase, operators are exempt from import duties and other forms of taxation applicable to goods intended for exploration activities. Exemptions are withdrawn at the production phase, but exceptions are made in certain instances, and the operator may be entitled to temporarily import goods tax-free for a two-year period ("Temporary Import"). A temporary Import may be extended for additional one year periods for up to two times upon the request of an operator, approval of the Ministry of Energy and Mines and authorization of the Superintendencia Nacional de Aduanas y de Administracion Tributaria (Peruvian Customs Agency).

Environmental Regulation

Before initiating any hydrocarbon activity (e.g. seismic exploration, drilling of exploration wells, etc.) the contractor must file and obtain an approval for an Environmental Impact Study (EIS), which is the most important permit related to HSE for any hydrocarbon project. This study includes technical, environmental and social evaluations of the project to be executed in order to define the activities that should be required for preventing, minimizing, mitigating and remediation of the possible negative environmental and social impacts that the hydrocarbon project may generate.

There are general environmental regulations for the protection of water, soils, air, endangered species, biodiversity, natural protected areas, etc. In addition, there are specific environmental regulations applicable to the hydrocarbon industry.

Argentina

Regulatory framework

From the 1920s to 1989, the Argentine public sector dominated the upstream segment of the Argentine oil and gas industry and the midstream and downstream segment of the business.

In 1989, Argentina enacted certain laws aimed at privatizing the majority of its state-owned companies and issued a series of presidential decrees (namely, Decrees No. 1055/89, 1212/89 and 1589/89 (the "Oil Deregulation Decrees"), relating specifically to deregulation of energy activities). The Oil Deregulation Decrees eliminated restrictions on imports and exports of crude oil, deregulated the domestic oil industry, and effective January 1, 1991, the prices of oil and petroleum products were also deregulated. In 1992, Law No. 24,145, referred to as the Privatization Law, privatized YPF and provided for transfer of hydrocarbon reservoirs from the Argentine government to the provinces, subject to the existing rights of the holders of exploration permits and production concessions.

In October 2004, the Argentine Congress enacted Law No. 25,943, creating a new state-owned energy company, Energía Argentina S.A. ("ENARSA"). The corporate purpose of ENARSA is the exploration and exploitation of solid, liquid and gaseous hydrocarbons; the transport, storage, distribution, commercialization and industrialization of these products; as well as the transportation and distribution of natural gas, and the generation, transportation, distribution and sale of electricity. Moreover, Law No. 25,943 granted ENARSA all offshore areas located beyond 12 nautical miles from the coastline up to the outer boundary of the continental shelf that were vacant at the time of the effectiveness of this law (i.e. November 3, 2004).

On May 3, 2012, the Argentine Congress passed the Hydrocarbons Sovereignty Act. This law declared achieving self-sufficiency in the supply of hydrocarbons, as well as in the exploitation, industrialization, transportation and sale of hydrocarbons, a national public interest and a priority for Argentina. In addition, the law expropriated 51% of the share capital of YPF, the largest Argentine oil company, from Repsol, the largest Spanish oil company.

On July 28, 2012, Presidential Decree 1277/2012, which regulated the Hydrocarbon Sovereignty Law, was released, creating a Strategic Planning and Coordination Committee for the National Hydrocarbon Investment Plan and vesting it with the power to set the sector's reference prices and to develop investment plans for the country to increase production and reserves. The decree introduced important changes to the rules governing Argentina's oil and gas industry, including the repeal of certain articles of Deregulation Decrees passed during 1989 relating to free marketability of hydrocarbons at negotiated prices, the deregulation of the oil and gas industry, freedom to import and export hydrocarbons and the ability to keep proceeds from export sales in foreign bank accounts.

On January 4, 2016, immediately after the new national administration took office, Presidential Decree 272/2015 was released. This Decree abrogated the provisions of the Presidential Decree 1277/2012 which had repealed the Deregulation Decrees. Thus, the Deregulation Decrees were reinstated. Other measures have also been taken by the new presidential administration aimed at reducing government intervention and reestablishing market forces in the oil & gas industry.

Domain and Jurisdiction of hydrocarbons resources

After a constitutional reform enacted in 1994, eminent domain over hydrocarbon resources lying in the territory of a provincial state is now vested in such provincial state, while eminent domain over hydrocarbon resources lying offshore on the continental platform beyond the jurisdiction of the coastal provincial states is vested in the federal state.

Thus, oil and gas exploration permits and exploitation concessions are now granted by each provincial government. A majority of the existing concessions were granted by the federal government prior to the enactment of Law No.26,197 and were thereafter transferred to the provincial states.

Regulation of exploration and production activities

New Hydrocarbon Act:

In October 31, 2014 the Argentine Republic Official Gazette published the text of Law No. 27,007, amending the Hydrocarbon Law No. 17,319.

The most relevant aspects of the new law are as follows:

- With regards to concessions, three types of concessions are provided, namely, conventional exploitation, unconventional exploitation, and exploitation in the continental shelf and territorial waters, establishing the respective terms for each type.
- The terms for hydrocarbon transportation concessions were adjusted in order to comply with the exploitation concessions terms.
- With regards to royalties, a maximum of 12% is established, which may reach 18% in the case of granted extensions, where the law also establishes the payment of an extension bond for a maximum amount equal to the amount resulting from multiplying the remaining proven reserves at the end of effective term of the concession by 2% of the average basin price applicable to the respective hydrocarbons over the 2 years preceding the time on which the extension was granted.
- The extension of the Investment Promotion Regime for the Exploitation of Hydrocarbons (Decree No. 929/2013) is established for projects representing a direct investment in foreign currency of at least 250 million dollars, increasing the benefits for other type of projects.

Regulation of transportation activities

Exploitation concessionaires have the exclusive right to obtain a transportation concession for the transport of oil and gas from the provincial states or the federal government, depending on the applicable jurisdiction. Such transportation concessions include storage, ports, pipelines and other fixed facilities necessary for the transportation of oil, gas and by-products. Transportation facilities with surplus capacity must transport third parties' hydrocarbons on an open-access basis, for a fee which is the same for all users on similar terms. As a result of the privatizations of YPF and Gas del Estado, a few common carriers of crude oil and natural gas were chartered and continue to operate to date.

Taxation

Exploitation concessionaires are subject to the general federal and provincial tax regime. The most relevant federal taxes are the income tax (35%), the value added tax (21%) and a tax on assets. The most relevant provincial taxes are the turnover tax (1% to 3%) and stamp tax. In 2002, in response to the economic crisis, the federal government adopted new taxes on oil and gas products, including export taxes ranging from 5% for by-products to 45% for crude oil. Such export taxes lapsed and terminated on January 6, 2016 on the 15th anniversary of their enactment.

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 as of the beginning of fiscal year 2018.

With this tax reform, the corporate income tax, which was 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.

C. Organizational structure

We are an exempted company incorporated pursuant to the laws of Bermuda. We operate and own our assets directly and indirectly through a number of subsidiaries. See an illustration of our corporate structure in Note 21 ("Subsidiary undertakings") to our Consolidated Financial Statements. During 2017, we decided to incorporate a subsidiary in the United Kingdom to conduct our businesses in Latin America by adopting all the key resolutions and decisions necessary for such purpose. In addition, as a result of tax reform enacted in the Netherlands during 2017, we decided to re-domicile our 100% owned Dutch subsidiaries to Spain.

D. Property, plant and equipment

See "—B. Business Overview—Title to properties."

ITEM 4A. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

A. Operating results

The following discussion of our financial condition and results of operations should be read in conjunction with our Consolidated Financial Statements and the notes thereto as well as the information presented under "Item 3. Key Information— A. Selected financial data."

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those discussed in the forward-looking statements as a result of various factors, including those set forth in "Item 3. Key Information—D. Risk factors" and "Forward-looking statements."

Factors affecting our results of operations

We describe below the year-to-year comparisons of our historical results and the analysis of our financial condition. Our future results could differ materially from our historical results due to a variety of factors, including the following:

Discovery and exploitation of reserves

Our results of operations depend on our level of success in finding, acquiring (including through bidding rounds) or gaining access to oil and natural gas reserves. While we have geological reports evaluating certain proved, contingent and prospective resources in our blocks, there is no assurance that we will continue to be successful in the exploration, appraisal, development and commercial production of oil and natural gas. The calculation of our geological and petrophysical estimates is complex and imprecise, and it is possible that our future exploration will not result in additional discoveries, and, even if we are able to successfully make such discoveries, there is no certainty that the discoveries will be commercially viable to produce.

For the year ended December 31, 2017, we made total capital expenditures of US$105.6 million (US$80.0 million, US$10.2 million, US$8.2 million, US$3.6 million and US$3.6 million in Colombia, Chile, Argentina, Peru and Brazil, respectively), consisting of US$49.5 million related to exploration.

Oil prices were volatile since the end of 2014. In preparation for continued volatility, we have developed multiple scenarios for our 2018 capital expenditure program. See "Item 4. Information on the Company –B. Business Overview—2018 Strategy and Outlook."

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

If oil prices average higher than the base budget price, we have the ability to allocate additional capital to more projects and increase its work and investment program and thereby further increase oil and gas production.

Our results of operations will be adversely affected in the event that our estimated oil and natural gas asset base does not result in additional reserves that may eventually be commercially developed. In addition, there can be no assurance that we will acquire new exploration blocks or gain access to exploration blocks that contain reserves. Unless we succeed in exploration and development activities, or acquire properties that contain new reserves, our anticipated reserves will continually decrease, which would have a material adverse effect on our business, results of operations and financial condition.

Oil and gas revenue and international prices

Our revenues are derived from the sale of our oil and natural gas production, as well as of condensate derived from the production of natural gas. The price realized for the oil we produce is generally linked to Brent or Vasconia.

The price realized for the natural gas we produce in Chile is linked to the international price of methanol, which is settled in the international markets in US$. The market price of these commodities is subject to significant fluctuation and has historically fluctuated widely in response to relatively minor changes in the global supply and demand for oil and natural gas, market uncertainty, economic conditions and a variety of additional factors. From January 1, 2013 to December 31, 2017, Brent spot prices ranged from a low of US$27.9 per barrel to a high of US$118.9 per barrel, Henry Hub natural gas average spot prices ranged from a low of US$1.7 per mmbtu to a high of US$6.0 per mmbtu, US Gulf methanol spot barge prices ranged from a low of US$250.0 per metric ton to a high of US$635.1 per metric ton. Furthermore, oil, natural gas and methanol prices do not necessarily fluctuate in direct relationship to each other.

As a consequence of the oil price crisis which started in the second half of 2014 (WTI and Brent, the main international oil price markers, fell more than 60% between October 2014 and February 2016), we took decisive steps in 2015 and 2016 to adapt to the new oil price environment. We reduced our capital expenditure program from US$238 million in 2014 to US$48 million in 2015 and US$39 million in 2016 and implemented significant cost reduction initiatives that resulted in production and operating costs being reduced by 49% (2016 versus 2014), and administrative expenses being reduced by 26% (2016 versus 2014), while increasing average production to approximately 22.4 mboepd and increasing our proved reserves to 73.6 mmboe.
In October 2016, we decided to manage part of our exposure to the volatile crude oil price using derivatives. For further information related to Commodity Risk Management Contracts, please see Note 8 to our Consolidated Financial Statements.

Additionally, the oil and gas we sell may be subject to certain discounts. For example, in Colombia, the price of oil we sell is based on Vasconia, a marker broadly used in the Llanos Basin, adjusted for certain marketing and quality discounts based on, among other things, API, viscosity, sulfur, delivery point and water content, as well as on certain transportation costs (including pipeline costs and trucking costs).

In Chile, the price of oil we sell to ENAP is based on Brent minus certain marketing and quality discounts. We have a long-term gas supply contract with Methanex. The price of the gas sold under this contract is determined based on a formula that takes into account various international prices of methanol, including US Gulf methanol spot barge prices, methanol spot Rotterdam prices and spot prices in Asia. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—A substantial or extended decline in oil, natural gas and methanol prices may materially adversely affect our business, financial condition or results of operations."

If the market prices of oil and methanol had fallen by 10% as compared to actual prices during the year, with all other variables held constant, taking into account the impact of the derivative contracts in place, post-tax loss for the year ended December 31, 2017 would have been higher by US$10.4 million (US$23.7 million in 2016).

In Brazil, prices for gas produced in the Manati Field are based on a long-term off-take contract with Petrobras. The price of gas sold under this contract is denominated in reais and is adjusted annually for inflation pursuant to the Brazilian General Market Price Index (Índice Geral de Preços—Mercado) (the "IGPM"). See Note 3 to our Consolidated Financial Statements.

Production and operating costs
Our production and operating costs consist primarily of expenses associated with the production of oil and gas, the most significant of which are gas plant leasing, facilities and wells maintenance (including pulling works), labor costs, contractor and consultant fees, chemical analysis, royalties and products, among others. As commodity prices increase or decrease, our production costs may vary. We have historically not hedged our costs to protect against fluctuations.

Availability and reliability of infrastructure
Our business depends on the availability and reliability of operating and transportation infrastructure in the areas in which we operate. Prices and availability for equipment and infrastructure, and the maintenance thereof, affect our ability to make the investments necessary to operate our business, and thus our results of operations and financial condition. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Our inability to access needed equipment and infrastructure in a timely manner may hinder our access to oil and natural gas markets and generate significant incremental costs or delays in our oil and natural gas production."

In order to mitigate the risk of unavailability of operating and transportation infrastructure, we have invested in the construction of plant and pipeline infrastructure to produce, process and store hydrocarbon reserves and to transport them to market.

Production levels
Our oil and gas production levels are heavily influenced by our drilling results, our acquisitions and to oil and natural gas prices.

We expect that fluctuations in our financial condition and results of operations will be driven by the rate at which production volumes from our wells decline. As initial reservoir pressures are depleted, oil and gas production from a given well will decline over time. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Unless we replace our oil and natural gas reserves, our reserves and production will decline over time. Our business is dependent on our continued successful identification of productive fields and prospects and the identified locations in which we drill in the future may not yield oil or natural gas in commercial quantities."

Contractual obligations
In order to protect our exploration and production rights in our license

areas, we must make and declare discoveries within certain time periods specified in our various special contracts, E&P Contracts and concession agreements. The costs to maintain or operate our license areas may fluctuate or increase significantly, and we may not be able to meet our commitments under these agreements on commercially reasonable terms or at all, which may force us to forfeit our interests in such areas. If we do not succeed in renewing these agreements, or in securing new ones, our ability to grow our business may be materially impaired. See "Item 3. Key Information—D. Risk factors—Risks relating to our business—Under the terms of some of our various CEOPs, E&P Contracts and concession agreements, we are obligated to drill wells, declare any discoveries and file periodic reports in order to retain our rights and establish development areas. Failure to meet these obligations may result in the loss of our interests in the undeveloped parts of our blocks or concession areas."

Acquisitions

Our results of operations are significantly affected by our past acquisitions. We generally incorporate our acquired business into our results of operations at or around the date of closing, such as our Colombian acquisitions in 2012 and our Rio das Contas acquisition in 2014, which limits the comparability of the period including such acquisitions with prior or future periods.

As described above, part of our strategy is to acquire and consolidate assets in Latin America. We intend to continue to selectively acquire companies, producing properties and concessions. As with our historical acquisitions, any future acquisitions could make year-to-year comparisons of our results of operations difficult. We may also incur additional debt, issue equity securities or use other funding sources to fund future acquisitions.

Functional and presentational currency

Our Consolidated Financial Statements are presented in US$, which is our functional and presentational currency. Items included in the financial information of each of our entities are measured using the currency of the primary economic environment in which the entity operates, or the functional currency, which is the US$ in each case, except for our Brazil operations, where the functional currency is the real.

Geographical segment reporting

In the description of our results of operations that follow, our "Other" operations reflect our non-Colombian, non-Chilean and non-Brazilian operations, primarily consisting of our Argentine, Peruvian (mainly related to the start-up of our operations in such country) and corporate head office operations.

We divide our business into five geographical segments—Colombia, Chile, Brazil, Peru and Argentina—that correspond to our principal jurisdictions of operation. Activities not falling into these four geographical segments are reported under a separate corporate segment that primarily includes certain corporate administrative costs not attributable to another segment.

Description of principal line items

The following is a brief description of the principal line items of our statement of income.

Revenue

Revenue includes the sale of crude oil, condensate and natural gas net of value-added tax ("VAT"), and discounts related to the sale (such as API and mercury adjustments) and overriding royalties due to the ex-owners of oil and gas properties where the royalty arrangements represent a retained working interest in the property. Revenue is recognized when the significant risks and rewards of ownership have been transferred to the buyer, the associated costs and amount of revenue can be estimated reliably, recovery of the consideration is probable, and there is no continuing management involvement with the goods.

Commodity risk management contracts

Includes realized and unrealized gains and losses arising from commodity risk management contracts.

Production and operating costs

For a description of our production and operating costs, see "—Factors affecting our results of operations."

Depreciation and write-off of unsuccessful efforts

Capitalized costs of proved oil and natural gas properties are depreciated on a licensed-area-by-licensed-area basis, using the unit of production method, based on commercial proved and probable reserves as calculated under the Petroleum Resources Management System methodology promulgated by the Society of Petroleum Engineers and the World Petroleum Council (the "PRMS"), which differs from SEC reporting guidelines pursuant to which certain information in the forepart of this annual report is presented. The calculation of the "unit of production" depreciation takes into account estimated future discovery and development costs. Changes in reserves and cost estimates are recognized prospectively. Reserves are converted to equivalent units on the basis of approximate relative energy content.

In particular, upon completion of the evaluation phase, a prospect is either transferred to oil and gas properties if it contains reserves, or is charged to profit and loss in the period in which the determination is made. See "—Critical accounting policies and estimates—Oil and gas accounting."

Geological and geophysical expenses

Geological and geophysical expenses consist of geosciences costs, including wages and salaries and share-based compensation not subject to capitalization, geological consultancy costs and costs relating to independent reservoir engineer studies.

Administrative expenses

Administrative costs consist of corporate costs such as director fees and travel expenses, new project evaluations and back-office expenses principally comprised of wages and salaries, share-based compensation, consultant fees and other administrative costs, including certain costs relating to acquisitions.

Our administrative expenses for the year ended December 31, 2017 increased by US$7.9 million, or 23%, compared to the year ended December 31, 2016 mainly due to higher staff costs resulting from increased scale of operations. However, administrative costs may increase as a result of our Peruvian and Argentinian operations, other acquisitions, increased activity or the impact of appreciation of local currencies in the countries where we operate.

Selling expenses

Selling expenses consist primarily of transportation and storage costs.

Impairment of non-financial assets

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

An impairment loss is recognized for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value minus costs to sell and value in use.

During 2017, we did not recognize an additional impairment, while in 2016 we recognized a reversal of impairment losses of US$5.7 million and in 2015 we recognized impairment losses amounting to US$149.6 million. See Note 36 to our Consolidated Financial Statements.

Financial costs

Financial costs consist of financial income offset by financial expenses. Financial income includes interest received from bank time deposits. Financial expenses principally include interest expense not subject to capitalization, bank charges and the unwinding of long-term liabilities.

Foreign exchange gain or loss

Foreign exchange gain or loss represents the effect of exchange rate differences.

Loss or profit for the period attributable to owners of the Company

Loss or profit for the period attributable to owners of the Company consists of losses or profit for the year less non-controlling interest.

Critical accounting policies and estimates

We prepare our Consolidated Financial Statements in accordance with IFRS and the interpretations of the IFRS Interpretations Committee ("IFRIC"), as adopted by the IASB. The preparation of the financial statements requires us to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses, and related disclosure of contingent assets and liabilities. We continually evaluate these estimates and assumptions based on the most recently available information, our own historical experience and various other assumptions that we believe to be reasonable under the circumstances. Since the use of estimates is an integral component of the financial reporting process, actual results could differ from those estimates.

An accounting policy is considered critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time such estimate is made, and if different accounting estimates that reasonably could have been used, or changes in the accounting estimates that are reasonably likely to occur periodically, could materially impact the financial statements. We believe that the following accounting policies represent critical accounting policies as they involve a higher degree of judgment and complexity in their application and require us to make significant accounting estimates. The following descriptions of critical accounting policies and estimates should be read in conjunction with our Consolidated Financial Statements and the accompanying notes and other disclosures.

Business combinations

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the fair market value of the assets acquired, equity instruments issued and liabilities incurred or assumed on the date of completion of the acquisition. Acquisition costs incurred are expensed and included in administrative expenses. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair market values at the acquisition date. The excess of the cost of acquisitions over fair market value of a company's share of the identifiable net assets acquired is recorded as goodwill. If the cost of the acquisition is less than a company's share of the net assets required, the difference is recognized directly in the statement of income.

The determination of fair value of identifiable acquired assets and assumed liabilities means that we are to make estimates and use valuation techniques, including independent appraisers. The valuation assumptions underlying each of these valuation methods are based on available updated information, including discount rates, estimated cash flows, market risk rates and other data. As a result, the process of identification and the related determination of fair values require complex judgments and significant estimates.

Cash flow estimates for impairment assessments

Cash flow estimates for impairment assessments 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 natural gas prices have exhibited significant volatility. Our forecasts for oil and natural gas revenues are based on prices derived from future price forecasts among industry analysts, as well as our own assessments. Estimates of future cash flows are generally based on assumptions of long-term prices and operating and development costs.

The process of estimating reserves requires significant judgments 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 D&M Reserves Report. Such estimates incorporate many factors and assumptions including:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and natural gas prices and quality differentials;
- anticipated effects of regulation by governmental agencies; and
- future development and operating costs.

Our management believes these factors and assumptions are reasonable based on the information available at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change.

For further information related to impairment of property, plant and equipment, please see Note 36 to our Consolidated Financial Statements.

Oil and gas accounting

Oil and gas exploration and production activities are accounted for in accordance with the successful efforts method on a field by field basis. We account for exploration and evaluation activities in accordance with IFRS 6, Exploration for and Evaluation of Mineral Resources, capitalizing exploration and evaluation costs until such time as the economic viability of producing the underlying resources is determined. Costs incurred prior to obtaining legal rights to explore are expensed immediately to the income statement.

Exploration and evaluation costs may include: license acquisition, geological and geophysical studies (i.e., seismic), direct labor costs and drilling costs of exploratory wells. No depreciation and/or amortization are charged during the exploration and evaluation phase. Upon completion of the evaluation phase, the prospects are either transferred to oil and gas properties or charged to expense in the period in which the determination is made, depending whether they have found reserves. 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. All field development costs are considered construction in progress until they are finished and capitalized within oil and gas properties, and are subject to depreciation once completed. Such costs may include the acquisition and installation of production facilities, development drilling costs (including dry holes, service wells and seismic surveys for development purposes), project-related engineering and the acquisition costs of rights and concessions related to proved properties.

Workovers of wells made to develop reserves and/or increase production are capitalized as development costs. Maintenance costs are charged to income when incurred.

Capitalized costs of proved oil and gas properties and production facilities and machinery are depreciated on a licensed area by 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 un-escalated price levels. Changes in reserves and cost estimates are recognized prospectively. Reserves are converted to equivalent units on the basis of approximate relative energy content.
Oil and gas reserves for purposes of our Consolidated Financial Statements are determined in accordance with PRMS, and were estimated by DeGolyer and MacNaughton, independent reserves engineers.

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 three and 10 years.

Asset retirement obligations

Obligations related to the plugging and abandonment of wells once operations are terminated may result in the recognition of significant liabilities. We record the fair value of the liability for asset retirement obligations in the period in which the wells are drilled. When the liability is initially recognized, the cost is also capitalized by increasing the carrying amount of the related asset. Over time, the liability is accreted to its present value at each reporting date, and the capitalized cost is depreciated over the estimated useful life of the related asset. Estimating the future abandonment costs is difficult and requires management to make assumptions and judgments because most of the obligations will be settled after many years. Technologies and costs are constantly changing, as are political, environmental, health, safety and public relations considerations. Consequently, the timing and future cost of dismantling and abandonment are subject to significant modification. Any change in the variables underlying our assumptions and estimates can have a significant effect on the liability and the related capitalized asset and future charges related to the retirement obligations. 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 liability recognized is based upon estimated future abandonment costs, wells subject to abandonment, time to abandonment, and future inflation rates.

Share-based payments

We provide several equity-settled, share-based compensation plans to certain employees and third-party contractors, composed of payments in the form of share awards and stock options plans.

Fair value of the stock option plans for employee or contractor services received in exchange for the grant of the options is recognized as an expense. The total amount to be expensed over the vesting period, which is the period over which all specified vesting conditions are to be satisfied, is determined by reference to the fair value of the options granted calculated using the Geometric Brownian Motion method. Determining the total value of our share-based payments requires the use of highly subjective assumptions, including the expected life of the stock options, estimated forfeitures and the price volatility of the underlying shares. The assumptions used in calculating the fair value of share-based payment represent management's best estimates, but these estimates involve inherent uncertainties and the application of management's judgment.

Non-market vesting conditions are included in assumptions in respect of the number of options that are expected to vest. At each balance sheet date, we revise our estimates of the number of options that are expected to vest. We recognize the impact of the revision to original estimates, if any, in the 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 recognized as an expense over the vesting period.

When options are exercised, we issue new common 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.

Taxation

The computation of our income tax expense involves the interpretation of applicable tax laws and regulations in many jurisdictions. The resolution of tax positions taken by us, 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.

In addition, we have tax-loss carry-forwards in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses can be utilized. Management judgment is exercised in assessing whether this is the case. To the extent that actual outcomes differ from management's estimates, taxation charges or credits may arise in future periods.

Contingencies

From time to time, we may be subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, environmental and health & safety matters. For example, from time to time, the Company receives notices of environmental, health and safety violations. Based on what our Management currently knows, such claims are not expected to have a material impact on the financial statements.

Recent accounting pronouncements

See Note 2.1.1 to our Consolidated Financial Statements.

Results of operations

The following discussion is of certain financial and operating data for the periods indicated. You should read this discussion in conjunction with our Consolidated Financial Statements and the accompanying notes.
As a consequence of the oil price crisis which started in the second half of 2014 (WTI and Brent, the main international oil price markers, fell more than 60% between August 2014 and March 2016), we have undertaken decisive measures to ensure our ability to both maximize the work program and preserve our cash.

During 2015 and 2016, we took decisive steps to adapt to the new oil price environment. We reduced our capital expenditure program from US$238 million in 2014 to US$48 million in 2015 and US$39 million in 2016 and implemented significant cost reduction initiatives that resulted in production and operating costs being reduced by 49% (2016 versus 2014), and administrative expenses being reduced by 26% (2016 versus 2014), while increasing average production to approximately 22.4 mboepd and increasing our proved reserves to 73.6 mmboe. For 2017, we designated a self-funded program that could be adapted to and provide production growth in different oil price scenarios. The main focus of the 2017 work program was to unlock the potential of the Tigana/Jacana oil field complex with a drilling program for 20 wells and new facility construction.

In preparation for continued volatility, we have developed multiple scenarios for our 2018 capital expenditure program. See "Item 4. Information on the Company –B. Business Overview—2018 Strategy and Outlook."

Year ended December 31, 2017 compared to year ended December 31, 2016

The following table summarizes certain of our financial and operating data for the years ended December 31, 2017 and 2016.

	For the year ended December 31 (in thousands of US$, except for percentages)		
	2017	2016	% Change from prior year
Revenue			
Net oil sales	279,162	145,193	92%
Net gas sales	50,960	47,477	7%
Revenue	330,122	192,670	71%
Commodity risk management contracts	(15,448)	(2,554)	505%
Production and operating costs	(98,987)	(67,235)	47%
Geological and geophysical expenses	(7,694)	(10,282)	(25)%
Administrative expenses	(42,054)	(34,170)	23%
Selling expenses	(1,136)	(4,222)	(73)%
Depreciation	(74,885)	(75,774)	(1)%
Write-off of unsuccessful efforts	(5,834)	(31,366)	(81)%
Impairment loss reversed for non-financial assets	-	5,664	(100)%
Other operating expense	(5,088)	(1,344)	279%
Operating profit (loss)	78,996	(28,613)	(376)%
Financial costs	(51,495)	(34,101)	51%
Foreign exchange (loss) gain	(2,193)	13,872	(116)%
Profit (Loss) before income tax	25,308	(48,842)	(152)%
Income tax expense	(43,145)	(11,804)	266%
Loss for the year	(17,837)	(60,646)	(71)%
Non-controlling interest	6,391	(11,554)	(155)%
Loss for the year attributable to owners of the Company	(24,228)	(49,092)	(51)%
Net production volumes			
Oil (mbbl) [2]	8,309	6,189	34%
Gas (mcf) [3]	10,562	11,911	(11)%
Total net production (mboe)	10,069	8,174	23%
Average net production (boepd)	27,586	22,394	23%
Average realized sales price			
Oil (US$ per bbl)	36.6	25.6	43%
Gas (US$ per mmcf)	5.3	4.5	18%
Average unit costs per boe (US$)			
Operating cost	7.4	7.3	1%
Royalties and other	3.0	1.5	100%
Production costs[1]	10.4	8.8	18%
Geological and geophysical expenses	0.8	1.3	(38)%
Administrative expenses	4.4	4.5	(2)%
Selling expenses	0.1	0.6	(83)%

[1] Calculated pursuant to FASB ASC 932

[2] We present production figures before deduction of royalties, as we believe that net production before royalties is more appropriate in light of our foreign operations and the attendant royalty regimes. Oil production figures presented on page F-76 are net of royalties.

[3] Corresponds to production measured after separation but prior to compression, which is the measure we used to monitor business performance. Gas production presented on page F-77 is gas measured at the point of delivery.

The following table summarizes certain financial and operating data.

	For the year ended December 31, (in thousands of US$)									
	2017					2016				
	Chile	Colombia	Brazil	Other	Total	Chile	Colombia	Brazil	Other	Total
Revenue	32,738	263,076	34,238	70	330,122	36,723	126,228	29,719	-	192,670
Depreciation	(23,730)	(40,010)	(10,809)	(336)	(74,885)	(31,355)	(31,148)	(12,974)	(297)	(75,774)
Impairment and write-off	(546)	(1,625)	(2,978)	(685)	(5,834)	(19,389)	(1,730)	(4,583)	-	(25,702)

Revenue

For the year ended December 31, 2017, crude oil sales were our principal source of revenue, with 85% and 15% of our total revenue from crude oil and gas sales, respectively. The following chart shows the change in oil and natural gas sales from the year ended December 31, 2016 to the year ended December 31, 2017.

	For the year ended December 31, (in thousands of US$)	
	2017	2016
Consolidated		
Sale of crude oil	279,162	145,193
Sale of gas	50,960	47,477
Total	**330,122**	**192,670**

	Year ended December 31		Change from prior year	
	(in thousands of US$, except for percentages)			
	2017	2016		%
By country				
Colombia	263,076	126,228	136,848	108%
Chile	32,738	36,723	(3,985)	(11)%
Brazil	34,238	29,719	4,519	15%
Other	70	-	70	100%
Total	**330,122**	**192,670**	**137,452**	**71%**

Revenue increased 71%, from US$192.7 million for the year ended December 31, 2016 to US$330.1 million for the year ended December 31, 2017, primarily as a result of higher oil revenues. Sales of crude oil increased due to higher realized prices and higher sold volumes of 7.9 mmbbl in the year ended December 31, 2017 compared to 5.9 mmbbl in the year ended December 31, 2016, and resulted in net revenue of US$279.2 million for the year ended December 31, 2017 compared to US$145.2 million for the year ended December 31, 2016. In addition, sales of gas increased from US$47.5 million for the year ended December 31, 2016 to US$51.0 million for the year ended December 31, 2017 due to increased sales volumes and higher realized prices. The increase in 2017 net revenue of US$137.5 million is mainly explained by:

- an increase of US$136.8 million in sales in Colombia, due to an increase in price and volume;
- a decrease of US$4 million in sales in Chile, including decreases of US$2.9 million in oil sales and US$1.1 million of gas sales; and
- an increase of US$4.3 million in gas sales in Brazil, related to our Manati operations;

all of which was due principally to higher oil and gas prices, as further described below.

Revenue attributable to our operations in Colombia for the year ended December 31, 2017 was US$263.1 million, compared to US$126.2 million for the year ended December 31, 2016, representing 80% and 66% of our total consolidated sales. The increase is related to an increase in oil deliveries from 5.4 mmbbl to 7.6 mmbbl and an increase in the average realized price per barrel of crude oil from US$24.4 per barrel to US$36.1 per barrel, primarily due to higher reference international prices.

Revenue attributable to our operations in Chile for the year ended December 31, 2017 was US$32.7 million, a 11% decrease from US$36.7 million for the year ended December 31, 2016, principally due to (1) decreased sales of crude oil of 0.3 mmbbl for the year ended December 31, 2017 compared to 0.5 mmbbl for the year ended December 31, 2016 (a decrease of 40%) due to the decline in oil base production, (2) a decrease in gas sales by US$1.1 million, due to decreased gas production levels as compared to the previous year. This was partially offset by increased average realized prices per barrel of crude oil from US$37.0 per barrel for the year December 31, 2016 to US$45.7 per barrel for the year ended December 31, 2017 (an increase of US$8.7 per barrel or a total of 24%). The increase in the average realized price per barrel was attributable to higher international reference prices. The contribution to our revenue during such years from our operations in Chile was 10% and 19%, respectively.

Revenue attributable to our operations in Brazil for the year ended December 31, 2017 was US$34.2 million, a 15% increase from US$29.7 million for the year ended December 31, 2016, principally due to higher gas prices. The contribution to our revenue from our operations in Brazil during the years ended December 31, 2017 and 2016 was 10% and 15%, respectively.

Production and operating costs

The following table summarizes our production and operating costs for the years ended December 31, 2017 and 2016.

	For the year ended December 31 (in thousands of US$, except for percentages)		
	2017	2016	% Change from prior year
Consolidated (including Colombia, Chile, Argentina, Peru and Brazil)			
Royalties	(28,697)	(11,497)	150%
Staff costs	(15,474)	(10,859)	42%
Transportation costs	(2,969)	(2,281)	30%
Well and facilities maintenance	(14,722)	(13,160)	12%
Consumables	(11,902)	(8,283)	44%
Equipment rental	(5,818)	(3,868)	50%
Other costs	(19,405)	(17,287)	12%
Total	**(98,987)**	**(67,235)**	**47%**

	Year ended December 31 (in thousands of US$)					
	2017			2016		
	Chile	Brazil	Colombia	Chile	Brazil	Colombia
By country						
Royalties	(1,314)	(3,134)	(24,236)	(1,495)	(2,721)	(7,281)
Staff costs	(5,582)	(241)	(9,461)	(5,866)	(85)	(5,530)
Transportation costs	(1,211)	-	(1,678)	(1,170)	-	(1,111)
Well and facilities maintenance	(3,817)	(2,982)	(7,923)	(6,122)	(1,419)	(5,619)
Consumables	(1,680)	-	(10,209)	(1,405)	-	(6,878)
Equipment rental	(59)	-	(5,706)	(42)	-	(3,826)
Other costs	(7,336)	(4,380)	(7,700)	(6,069)	(4,234)	(6,362)
Total	**(20,999)**	**(10,737)**	**(66,913)**	**(22,169)**	**(8,459)**	**(36,607)**

Consolidated production and operating costs increased 47%, from US$67.2 million for the year ended December 31, 2016 to US$99.0 million for the year ended December 31, 2017, primarily due to higher royalties paid in cash, in line with increased production (the Jacana oil field accumulated more than 5 mmbbl during the year ended December 31, 2017, triggering a higher royalty rate in Colombia), and higher oil prices, and increased operating costs related to higher sales volumes.

Production and operating costs in Colombia increased 83%, to US$66.9 million for the year ended December 31, 2017, as compared to US$36.6 million for the year ended December 31, 2016, primarily due to (i) higher royalties of US$17.0 million, in line with increased production (the Jacana oil field accumulated more than 5 mmbbl during the year ended December 31, 2017, triggering a higher royalty rate in Colombia) and higher oil prices, and (ii) increased costs associated with higher production and the reopening of the Cuerva and Yamu Blocks, which are mature fields with higher operating costs than the Llanos 34 Block. In addition, operating costs per boe in Colombia increased to US$5.6 per boe for the year ended December 31, 2017 from US$5.4 per boe for the year ended December 31, 2016.

Production and operating costs in Chile decreased by 5% to US$21.0 million due to lower oil and gas production levels. Costs per boe increased to US$20.3 per boe from US$15.8 per boe in 2016. In the year ended December 31, 2017, the revenue mix for Chile was 48.5% oil and 51.5% gas, whereas for the same period in 2016 it was 51.1% oil and 48.9% gas.

Production and operating costs in Brazil increased by 27%, to US$10.7 million for the year ended December 31, 2017, as compared to the year ended December 31, 2016, mainly resulting from non-recurring maintenance costs in Manati Field. Operating costs per boe increased to US$7.8 for the year ended December 31, 2017 from US$5.8 per boe for the year ended December 31, 2016.

Geological and geophysical expenses

	Year ended December 31		Change from prior year	
	(in thousands of US$, except for percentages)			
	2017	2016		%
Colombia	(2,231)	(4,296)	2,065	(48)%
Chile	(858)	(1,671)	813	(49)%
Brazil	(1,007)	(1,053)	46	(4)%
Other	(3,598)	(3,262)	(336)	10%
Total	**(7,694)**	**(10,282)**	**2,588**	**(25)%**

Geological and geophysical expenses decreased 25%, from US$10.3 million for the year ended December 31, 2016 to US$7.7 million for the year ended December 31, 2017, primarily as the result of higher allocation to capitalized projects due to increased drilling activity levels.

Administrative costs

	Year ended December 31		Change from prior year	
	(in thousands of US$, except for percentages)			
	2017	2016		%
Colombia	(17,567)	(14,715)	(2,852)	19%
Chile	(6,331)	(7,153)	822	(11)%
Brazil	(2,444)	(3,085)	641	(21)%
Other	(15,712)	(9,217)	(6,495)	70%
Total	**(42,054)**	**(34,170)**	**(7,884)**	**23%**

Administrative costs increased 23%, from US$34.2 million for the year ended December 31, 2016 to US$42.1 million for the year ended December 31, 2017, mainly due to higher staff costs and consulting fees resulting from an increased scale of operations.

Selling expenses

	Year ended December 31,		Change from prior year	
	(in thousands of US$, except for percentages)			
	2017	2016		%
Colombia	(250)	(2,830)	2,580	(91)%
Chile	(688)	(994)	306	(31)%
Brazil	-	(20)	20	(100)%
Other	(198)	(378)	180	(48)%
Total	**(1,136)**	**(4,222)**	**3,086**	**(73)%**

Selling expenses decreased 73%, from US$4.2 million for year ended December 31, 2016 to US$1.1 million for the year ended December 31, 2017, primarily due to the Trafigura offtake agreement as sales occur at the wellhead in our Colombian operations, which are recorded as a discount to the oil price.

Commodity risk management contracts

We recorded a loss of US$15.4 million related to commodity risk management contracts for the year ended December 31, 2017. Realized losses reflect cash settled transactions and unrealized losses reflect non-cash changes between the contract values and the forward Brent oil curve.

Depreciation

Depreciation charges decreased by 1% from US$75.8 million for the year ended December 31, 2016 to US$74.9 million for the year ended December 31, 2017, mainly due to lower production levels in Chile and Brazil. and lower depreciation costs per barrel in Colombia. Depreciation costs per boe decreased from US$9.9 to US$7.9 per boe.

Operating profit (loss)

	Year ended December 31,		Change from prior year	
	(in thousands of US$, except for percentages)			
	2017	2016		%
Colombia	116,290	31,464	84,826	270%
Chile	(19,675)	(44,969)	25,294	(56)%
Brazil	4,434	(644)	5,078	(789)%
Other	(22,053)	(14,464)	(7,589)	52%
Total	**78,996**	**(28,613)**	**107,609**	**(376)%**

We recorded an operating profit of US$79.0 million for the year ended December 31, 2017, a 376% improvement from the operating loss of US$28.6 million for the year ended December 31, 2016, primarily due to an increase in revenue and other gains and a decrease in certain expenses and depreciation, as described above. In 2016, we recorded a gain on non-cash impairments reversal of non-financial assets amounting to US$5.7 million in Colombia, resulting from an improved oil price environment and improvements in cost structure.

Financial costs

Financial costs increased 51% to US$51.5 million for the year ended December 31, 2017 as compared to US$34.1 million for the year ended December 31, 2016, mainly due to one-time costs on the cancellation of 2020 Notes for an amount of US$17.6 million.

Foreign exchange (loss) gain

Foreign exchange variation decreased from a gain of US$13.9 million for the year ended December 31, 2016 compared to a loss of US$2.2 million for the year ended December 31, 2017, mainly due to the appreciation of the Brazilian real in the 2016 period and its depreciation in the 2017 period. Foreign exchange differences are mainly generated from changes in the value of the Brazilian real over the U.S. Dollar-denominated debt incurred at the local subsidiary level, where the functional currency is the Brazilian real.

Profit (Loss) before income tax

	Year ended December 31		Change from prior year	
	(in thousands of US$, except for percentages)			
	2017	2016		%
Colombia	113,028	25,845	87,183	337%
Chile	(32,801)	(58,017)	25,216	(43)%
Brazil	(2,529)	8,762	(11,291)	(129)%
Other	(52,390)	(25,432)	(26,958)	106%
Total	**25,308**	**(48,842)**	**74,150**	**(152)%**

For the year ended December 31, 2017, we recorded a profit before income tax of US$25.3 million, compared to a loss of US$48.8 million for the year ended December 31, 2016, primarily due to profits recorded in our Colombian operations.

Income tax (expense)

	Year ended December 31		Change from prior year	
	(in thousands of US$, except for percentages)			
	2017	2016		%
Colombia	(45,406)	(11,969)	(33,437)	279%
Chile	856	2,155	(1,299)	(60)%
Brazil	36	(2,764)	2,800	(101)%
Other	1,369	774	595	77%
Total	**(43,145)**	**(11,804)**	**(31,341)**	**266%**

Income tax expense increased 266%, from US$11.8 million for the year ended December 31, 2016 to US$43.1 million for the year ended December 31, 2017, as a result of higher profits in Colombia.

Loss Profit for the year

	Year ended December 31		Change from prior year	
	(in thousands of US$, except for percentages)			
	2017	2016		%
Colombia	67,622	13,876	53,746	387%
Chile	(31,945)	(55,862)	23,917	(43)%
Brazil	(2,493)	5,998	(8,491)	(142)%
Other	(51,021)	(24,658)	(26,363)	107%
Total	**(17,837)**	**(60,646)**	**42,809**	**(71)%**

For the year ended December 31, 2017, we recorded a net loss of US$17.8 million as a result of the reasons described above.

Loss Profit for the year attributable to owners of the Company

Loss for the year attributable to owners of the Company decreased by 51% to US$24.2 million, compared to a loss for the year ended December 31, 2016 of US$49.1 million for the reasons described above. Profit attributable to non-controlling interest increased by 155% to US$6.4 million for the year ended December 31, 2017 as compared to a loss of US$11.6 million for the year ended December 31, 2016.

Year ended December 31, 2016 compared to year ended December 31, 2015

The following table summarizes certain of our financial and operating data for the years ended December 31, 2016 and 2015.

For the year ended December 31 (in thousands of US$, except for percentages)	2016	2015	% Change from prior year
Revenue			
Net oil sales	145,193	162,629	(11)%
Net gas sales	47,477	47,061	1%
Net revenue	**192,670**	**209,690**	**(8)%**
Commodity risk management contracts	(2,554)	—	100%
Production and operating costs	(67,235)	(86,742)	(22)%
Geological and geophysical expenses	(10,282)	(13,831)	(26)%
Administrative expenses	(34,170)	(37,471)	(9)%
Selling expenses	(4,222)	(5,211)	(19)%
Depreciation	(75,774)	(105,557)	(28)%
Write-off of unsuccessful efforts	(31,366)	(30,084)	4%
Impairment loss for non-financial assets	5,664	(149,574)	(104)%
Other operating expense	**(1,344)**	**(13,711)**	**(90)%**
Operating loss	(28,613)	(232,491)	(88)%
Financial costs	(34,101)	(35,655)	(4)%
Foreign exchange gain (loss)	13,872	(33,474)	(141)%
Loss before income tax	(48,842)	(301,620)	(84)%
Income tax (expense) benefit	**(11,804)**	**17,054**	**(169)%**
Loss for the year	(60,646)	(284,566)	(79)%
Non-controlling interest	(11,554)	(50,535)	(77)%
Loss for the year attributable to owners of the Company	**(49,092)**	**(234,031)**	**(79)%**
Net production volumes			
Oil (mbbl) [3]	6,189	5,518	12%
Gas (mcf) [2]	11,911	11,493	4%
Total net production (mboe)	8,174	7,434	10%
Average net production (boepd)	22,394	20,367	10%
Average realized sales price			
Oil (US$ per bbl)	25.6	32.1	(20)%
Gas (US$ per mmcf)	4.5	4.6	(2)%
Average unit costs per boe (US$)			
Operating cost	7.3	10.5	(30)%
Royalties and other	1.5	1.9	(21)%
Production costs[1]	8.8	12.4	(29)%
Geological and geophysical expenses	1.3	2.0	(35)%
Administrative expenses	4.5	5.4	(17)%
Selling expenses	0.6	0.7	(14)%

(1) Calculated pursuant to FASB ASC 932.
(2) We present production figures before deduction of royalties, as we believe that net production before royalties is more appropriate in light of our foreign operations and the attendant royalty regimes. Oil production figures presented on page F-76 are net of royalties.
(3) Corresponds to production measured after separation but prior to compression, which is the measure we used to monitor business performance. Gas production presented on page F-77 is gas measured at the point of delivery.

The following table summarizes certain financial information and operating data.

	Year ended December 31 (in thousands of US$)									
					2016					2015
	Chile	Colombia	Brazil	Other	Total	Chile	Colombia	Brazil	Other	Total
Net revenue	36,723	126,228	29,719	—	192,670	44,808	131,897	32,388	597	209,690
Depreciation	(31,355)	(31,148)	(12,974)	(297)	(75,774)	(39,227)	(52,434)	(13,568)	(328)	(105,557)
Impairment and write-off	(19,389)	(1,730)	(4,583)	—	(25,702)	(130,266)	(49,392)	—	—	(179,658)

Revenue

For the year ended December 31, 2016, crude oil sales were our principal source of revenue, with 75% and 25% of our total revenue from crude oil and gas sales, respectively. The following chart shows the change in oil and natural gas sales from the year ended December 31, 2015 to the year ended December 31, 2016.

	For the year ended December 31 (in thousands of US$)	
	2016	2015
Consolidated		
Sale of crude oil	145,193	162,629
Sale of gas	47,477	47,061
Total	**192,670**	**209,690**

	Year ended December 31 (in thousands of US$, except for percentages)			
	2016	2015		% Change from prior year
By country				
Colombia	126,228	131,897	(5,669)	(4)%
Chile	36,723	44,808	(8,085)	(18)%
Brazil	29,719	32,388	(2,669)	(8)%
Other	—	597	(597)	(100)%
Total	**192,670**	**209,690**	**(17,020)**	**(8)%**

Revenue decreased 8%, from US$209.7 million for the year ended December 31, 2015 to US$192.7 million for the year ended December 31, 2016, primarily as a result of lower prices. Sales of crude oil increased to 5.9 mmbbl in the year ended December 31, 2016 compared to 5.3 mmbbl in the year ended December 31, 2015, and resulted in net revenue of US$145.2 million for the year ended December 31, 2016 compared to US$162.6 for the year ended December 31, 2015. In addition, sales of gas increased from US$47.1 million for the year ended December 31, 2015 to US$47.5 million for the year ended December 31, 2016 due to higher production.

The decrease in 2016 net revenue of US$17.0 million is mainly explained by:

- a decrease of US$5.7 million in oil sales in Colombia
- a decrease of US$8.1 million in sales in Chile, including US$10.4 million in oil sales partially offset by an increase of US$2.3 million of gas sales.
- a decrease of US$2.7 million in sales in Brazil, related to our Manati operations and including US$0.3 million of oil sales and US$2.4 million of gas sales, all of which was due principally to lower oil and gas prices, as further described below.

Revenue attributable to our operations in Colombia for the year ended December 31, 2016 was US$126.2 million, compared to US$131.9 million for the year ended December 31, 2015, representing 66% and 63% of our total consolidated sales. The decrease is related to a decrease in the average realized prices per barrel of crude oil from US$28.8 per barrel to US$24.4 per barrel, primarily due to lower reference international prices. This was partially offset by increased sales of crude oil, from 4.6 mmbbl for the year ended December 31, 2015 to 5.4 mmbbl for the year ended December 31, 2016, an increase of 17%. This increase resulted mainly from the development and appraisal of the Jacana and Tigana fields in the Llanos 34 Block.

Revenue attributable to our operations in Chile for the year ended December 31, 2016 was US$36.7 million, a 18% decrease from US$44.8 million for the year ended December 31, 2015, principally due to (1) decreased sales of crude oil of 0.5 mmbbl for the year ended December 31, 2016 compared to 0.7 mmbbl for the year ended December 31, 2015 (a decrease of 29%) due to the decline in oil base production, (2) decreased average realized prices per barrel of crude oil from US$42.2 per barrel for the year December 31, 2015 to US$37.0 per barrel for the year ended December 31, 2016 (a decrease of US$5.2 per barrel or a total of 12%). The decrease in the average realized price per barrel was attributable to lower international reference prices. This was partially offset by an increase in gas sales by US$2.3 million, due to increased gas production levels as compared to the previous year. The contribution to our revenue during such years from our operations in Chile was 19% and 21%, respectively.

Revenue attributable to our operations in Brazil for the year ended December 31, 2016 was US$29.7 million, a 8% decrease from US$32.4 million for the year ended December 31, 2015, principally due to decreased sales of gas of 5.8 mmcf for the year ended December 31, 2016 compared to 6.7 mmcf for the year ended December 31, 2015 (a decrease of 13%) due to lower industrial demand. The contribution to our revenue during such years from our operations in Brazil was 15%.

Production and operating costs

The following table summarizes our production and operating costs for the years ended December 31, 2016 and 2015.

	For the year ended December 31 (in thousands of US$, except for percentages)		
	2016	2015	% Change from prior year
Consolidated (including Colombia, Chile, Argentina, Peru and Brazil)			
Royalties	(11,497)	(13,155)	(13)%
Staff costs	(10,859)	(18,562)	(41)%
Transportation costs	(2,281)	(4,511)	(49)%
Well and facilities maintenance	(13,160)	(19,974)	(34)%
Consumables	(8,283)	(8,591)	(4)%
Equipment rental	(3,868)	(3,517)	10%
Other costs	(17,287)	(18,432)	(6)%
Total	**(67,235)**	**(86,742)**	**(22)%**

	Year ended December 31 (in thousands of US$)					
	2016			2015		
	Chile	Brazil	Colombia	Chile	Brazil	Colombia
By country						
Royalties	(1,495)	(2,721)	(7,281)	(1,973)	(2,998)	(8,150)
Staff costs	(5,866)	(85)	(5,530)	(7,680)	—	(9,322)
Transportation costs	(1,170)	—	(1,111)	(2,441)	—	(2,068)
Well and facilities maintenance	(6,122)	(1,419)	(5,619)	(10,628)	(1,651)	(7,611)
Consumables	(1,405)	—	(6,878)	(1,851)	—	(6,726)
Equipment rental	(42)	—	(3,826)	(101)	—	(3,404)
Other costs	(6,069)	(4,234)	(6,362)	(4,030)	(3,407)	(11,253)
Total	**(22,169)**	**(8,459)**	**(36,607)**	**(28,704)**	**(8,056)**	**(48,534)**

Consolidated production and operating costs decreased 22%, from US$86.7 million for the year ended December 31, 2015 to US$67.2 million for the year ended December 31, 2016, primarily due to cost reduction efforts and efficiencies, partially offset by increased volume sold.
Production and operating costs in Colombia decreased 25%, to US$36.6 million for the year ended December 31, 2016, as compared to the year ended December 31, 2015, primarily due to cost reduction efforts. In addition, operating costs per boe in Colombia decreased to US$5 per boe for the year ended December 31, 2016 from US$9 per boe for the year ended December 31, 2015.

Production and operating costs in Chile decreased by 23%, due to cost reduction initiatives and operating costs per boe decreased to US$16 per boe from US$21 per boe in 2015. In the year ended December 31, 2016, the revenue mix for Chile was 51.1% oil and 48.9% gas, whereas for the same period in 2015 it was 65.1% oil and 34.9% gas.

Production and operating costs in Brazil increased by 5%, to US$8.4 million for the year ended December 31, 2016, as compared to the year ended December 31, 2015, primarily due to decrease in production. Operating costs per boe increased to US$6 for the year ended December 31, 2016 from US$4 per boe for the year ended December 31, 2015.

Geological and geophysical expenses

	For the year ended December 31 (in thousands of US$, except for percentages)			
	2016	2015		% Change from prior year
Colombia	(4,296)	(2,798)	(1,498)	54%
Chile	(1,671)	(4,749)	3,078	(65)%
Brazil	(1,053)	(1,103)	50	(5)%
Other	(3,262)	(5,181)	1,919	(37)%
Total	**(10,282)**	**(13,831)**	**3,549**	**(26)%**

Geological and geophysical expenses decreased 26%, from US$13.8 million for the year ended December 31, 2015 to US$10.3 million for the year ended December 31, 2016, primarily as the result of higher allocation to capitalized projects and lower staff costs.

Administrative costs

	For the year ended December 31 (in thousands of US$, except for percentages)			
	2016	2015		% Change from prior year
Colombia	(14,715)	(10,579)	(4,136)	39%
Chile	(7,153)	(10,978)	3,825	(35)%
Brazil	(3,085)	(2,936)	(149)	5%
Other	(9,217)	(12,978)	3,761	(29)%
Total	**(34,170)**	**(37,471)**	**3,301**	**(9)%**

Administrative costs decreased 9%, from US$37.5 million for the year ended December 31, 2015 to US$34.2 million for the year ended December 31, 2016, primarily as a result of continuing financial discipline.

Selling expenses

	For the year ended December 31 (in thousands of US$, except for percentages)			
	2016	2015		% Change from prior year
Colombia	(2,830)	(3,658)	828	(23)%
Chile	(994)	(1,085)	91	(8)%
Brazil	(20)	—	(20)	100%
Other	(378)	(468)	90	(19)%
Total	**(4,222)**	**(5,211)**	**989**	**(19)%**

Selling expenses decreased 19%, from US$5.2 million for year ended December 31, 2015 to US$4.2 million for the year ended December 31, 2016, primarily due to a change in the commercialization mix increasing sales at wellhead in our Colombian operations. In our Chilean operations, selling expenses were 8% lower compared to prior year, primarily as a result of lower oil production levels.

Operating (loss) profit

	For the year ended December 31 (in thousands of US$, except for percentages)			
	2016	2015		% Change from prior year
Colombia	31,464	(37,227)	68,691	(185)%
Chile	(44,969)	(180,264)	135,295	(75)%
Brazil	(644)	6,639	(7,283)	(110)%
Other	(14,464)	(21,639)	7,175	(33)%
Total	**(28,613)**	**(232,491)**	**203,878**	**(88)%**

We recorded an operating loss of US$28.6 million for the year ended December 31, 2016, an 88% improvement from the operating loss of US$232.5 million for the year ended December 31, 2015, primarily due to the recognition in 2015 of non-cash impairments of non-financial assets amounting to US$149.6 million (US$104.5 million recorded in Chile and US$45.1 million in Colombia). In 2016, we recorded a gain on non-cash impairments reversal of non-financial assets amounting to US$5.7 million in Colombia, resulting from an improved oil price environment and improvements in cost structure.

Financial costs

Financial costs decreased 4% to US$34.1 million for the year ended December 31, 2016 as compared to US$35.7 million for the year ended December 31, 2015, mainly due to the impact of lower bank charges and higher interest gains.

Foreign exchange gain (loss)

Foreign exchange variation was 141% to a gain of US$13.9 million for the year ended December 31, 2016 as compared to US$33.5 million loss for the year ended December 31, 2015, mainly because of the appreciation of the real over US$ denominated net debt incurred at the local subsidiary level, where the functional currency is the *real*.

(Loss) Profit before income tax

	For the year ended December 31 (in thousands of US$, except for percentages)			
	2016	2015		% Change from prior year
Colombia	25,845	(38,339)	64,184	(167)%
Chile	(58,017)	(193,683)	135,666	(70)%
Brazil	8,762	(37,980)	46,742	(123)%
Other	(25,432)	(31,618)	6,186	(20)%
Total	**(48,842)**	**(301,620)**	**252,778**	**(84)%**

For the year ended December 31, 2016, we recorded a loss before income tax of US$48.8 million, compared to a loss of US$301.6 million for the year ended December 31, 2015, primarily due to decreased losses from our Chilean and Other operations and profits recorded in our Colombian and Brazilian operations.

Income tax (expense) benefit

	For the year ended December 31 (in thousands of US$, except for percentages)			
	2016	2015		% Change from prior year
Colombia	(11,969)	(620)	(11,349)	1,830%
Chile	2,155	16,893	(14,738)	(87)%
Brazil	(2,764)	8,357	(11,121)	(133)%
Other	774	(7,576)	8,350	(110)%
Total	**(11,804)**	**17,054**	**(28,858)**	**(169)%**

Income tax expense decreased 169%, from US$17.1 million for the year ended December 31, 2015 to a loss of US$11.8 million for the year ended December 31, 2016, as a result of increased results of operations, mainly related to Colombia and Brazil.

(Loss) Profit for the year

	For the year ended December 31 (in thousands of US$, except for percentages)			
	2016	2015		% Change from prior year
Colombia	13,876	(38,959)	52,835	(136)%
Chile	(55,862)	(176,789)	120,927	(68)%
Brazil	5,998	(29,623)	35,621	(120)%
Other	(24,658)	(39,195)	14,537	(37)%
Total	**(60,646)**	**(284,566)**	**223,920**	**(79)%**

For the year ended December 31, 2016, we recorded a loss of US$60.6 million as a result of the reasons described above.

(Loss) Profit for the year attributable to owners of the Company

Loss for the year attributable to owners of the Company decreased by 79% to US$49.1 million, for the reasons described above. Loss attributable to non-controlling interest decreased by 77% to US$11.6 million for the year ended December 31, 2016 as compared to the prior year.

B. Liquidity and capital resources

Overview

Our financial condition and liquidity is and will continue to be influenced by a variety of factors, including:

- changes in oil and natural gas prices and our ability to generate cash flows from our operations;
- our capital expenditure requirements;
- the level of our outstanding indebtedness and the interest we are obligated

to pay on this indebtedness; and

- changes in exchange rates which will impact our generation of cash flows from operations when measured in US$, and the *real*.

Our principal sources of liquidity have historically been contributed shareholder equity, debt financings and cash generated by our operations. Since 2005 to 2017, we have raised approximately US$200 million in equity offerings at the holding company level and nearly US$1 billion through debt arrangements with multilateral agencies such as the IFC, gas prepayment facilities with Methanex, international bond issuances and bank financings, described further below, which have been used to fund our capital expenditures program and acquisitions and to increase our liquidity.
We have also raised US$182.1 million to date through our strategic partnership with LGI following the sale of minority interests in our Colombian and Chilean operations.
In February 2014, we commenced trading on the NYSE and raised US$98 million (before underwriting commissions and expenses), including the over-allotment option granted to and exercised by the underwriters, through the issuance of 13,999,700 common shares.

In February 2013, we issued US$300.0 million aggregate principal amount of 7.50% senior secured notes due 2020 (the "Notes due 2020").

In December 2015, we entered into an offtake and prepayment agreement with Trafigura under which we will sell a portion of our Colombian crude oil production to Trafigura in exchange for advance payments of up to US$100 million, subject to applicable volumes corresponding to the terms of the agreement. Funds committed by Trafigura were available to us upon request until September 2017 to be repaid by us on a monthly basis through future oil deliveries until December 2018. As of October 2017, we are no longer obligated to pay a commitment fee for any unused commitment under the Trafigura Agreement.

In September 2017, we issued US$425.0 million aggregate principal amount of senior secured notes due 2024. The Notes due 2024 mature on September 21, 2024 and bear interest at a fixed rate of 6.50% and a yield of 6.50% per year. Interest on the Notes due 2024 is payable semi-annually in arrears on March 21 and September 21 of each year. The Indenture governing our Notes due 2024 contains incurrence-based limitations on the amount of indebtedness we can incur. This situation may limit our capacity to incur additional indebtedness, other than permitted debt, as specified in the indenture governing the Notes. The net proceeds from the Notes were used by us (i) to make a capital contribution to our wholly-owned subsidiary, GeoPark Latin America Limited Agencia en Chile, 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 a call premium, and (ii) for general corporate purposes, including capital expenditures, such as the acquisition of Aguada Baguales, El Porvenir and Puesto Touquet blocks in Neuquen basin in Argentina, and to repay existing indebtedness, including the Itaú loan. On March 21 2018, we made a semi-annual interest payment on the Notes due 2024 in the amount of US$13.8 million.

We repurchased US$284.0 million aggregate principal amount of the outstanding Notes due 2020 in September 2017, and redeemed the remaining US$16.0 million aggregate principal amount outstanding in October 2017, using funds received in connection with the settlement of the Notes due 2024. The total consideration paid for the validly tendered and accepted Notes due 2020 was US$1,041.25 per US$1,000 principal amount of 2020 Notes, which included an early tender payment of US$30 per US$1,000 principal amount of 2020 Notes for holders who tendered their notes by September 19, 2017, plus accrued and unpaid interest to, but not including, September 21, 2017. We redeemed the remaining US$16.0 million aggregate principal amount outstanding of the Notes due 2020 at a price equal to 103.75% of the principal amount thereof, plus accrued and unpaid interest (including additional amounts, if any) from August 11, 2017 to, but excluding October 21, 2017.

We believe that our current operations and 2018 capital expenditures program can be funded from cash flow from existing operations and cash on hand. Should our operating cash flow decline due to unforeseen events, including delivery restrictions or a protracted downturn in oil and gas prices, we would examine measures such as further capital expenditure program reductions, pre-sale agreements, disposition of assets, or issuance of equity, among others.

Capital expenditures

In the past, we have funded our capital expenditures with proceeds from equity offerings, credit facilities, debt issuances and pre-sale agreements, as well as through cash generated from our operations. We expect to incur substantial expenses and capital expenditures as we develop our oil and natural gas prospects and acquire additional assets. See "Item 4. Information on the Company –B. Business Overview—2018 Strategy and Outlook."

In the year ended December 31, 2017, we made total capital expenditures of US$105.6 million (US$80.0 million, US$10.2 million, US$8.2 million, US$3.6 million and US$3.6 million in Colombia, Chile, Argentina, Peru and Brazil, respectively).

In the year ended December 31, 2016, we made total capital expenditures of US$39.3 million (US$26.2 million, US$7.8 million, US$1.7 million and US$3.6 million in Colombia, Chile, Argentina and Brazil, respectively).

Cash flows

The following table sets forth our cash flows for the periods indicated:

	Year ended December 31, (in thousands of US$)		
Cash flows provided by (used in)	2017	2016	2015
Operating activities	142,158	82,884	25,895
Investing activities	(105,604)	(39,306)	(48,842)
Financing activities	23,968	(51,136)	(18,022)
Net increase (decrease) in cash and cash equivalents	**60,522**	**(7,558)**	**(40,969)**

Cash flows provided by operating activities

For the year ended December 31, 2017, cash provided by operating activities was US$142.2 million, a 72% increase from US$82.9 million for the year ended December 31, 2016, resulting from the increase in oil prices in 2017 as compared to 2016, net of a US$15.6 million advance payment paid in December 2017 to Pluspetrol, as a security deposit related to the recently announced acquisition of Aguada Baguales, El Porvenir and Puesto Touquet blocks in Neuquen basin in Argentina.

For the year ended December 31, 2016, cash provided by operating activities was US$82.9 million, a 220% increase from US$25.9 million for the year ended December 31, 2015, resulting from cost reduction efforts, lower income tax paid and increased funds from working capital, including customer advance payments from Trafigura.

Cash flows used in investing activities

For the year ended December 31, 2017, cash used in investing activities was US$105.6 million, a 169% increase from US$39.3 million for the year ended December 31, 2016. This increase was related to higher capital expenditures in Colombia, Chile, Argentina and Peru in 2017 as compared to 2016.

For the year ended December 31, 2016, cash used in investing activities was US$39.3 million, a 20% decrease from US$48.8 million for the year ended December 31, 2015. This decrease was related to lower capital expenditures in Colombia, Chile and Brazil in 2016 as compared to 2015, despite having similar activity levels.

Cash flows from financing activities

Cash from financing activities was US$24.0 million for the year ended December 31, 2017, compared to US$51.1 million used in financing activities for the year ended December 31, 2016. This change was principally related to net proceeds from the issuance of 2024 Notes of US$418.3 million offset by principal paid of US$355.0 million related to the payment of 2020 Notes and the prepayment of the Itaú loan.

Cash used in financing activities was US$51.1 million for the year ended December 31, 2016, compared to US$18.0 million for the year ended December 31, 2015. This change was principally the result of principal payments related to Itaú loan and dividends distribution to non-controlling interest.

Indebtedness

As of December 31, 2017 and 2016, we had total outstanding indebtedness of US$426.2 million and US$358.7 million, respectively, as set forth in the table below.

	As of December 31, (in thousands of US$)	
BCI Loans	2016	2017
Bond GeoPark Latin America Agencia en Chile (Notes due 2020)	80 —	141 304,059
Bond GeoPark Limited (Notes due 2024)	426,124	—
Banco de Chile	—	4,709
Rio das Contas Credit Facility	—	49,763
Total	**426,204**	**358,672**

Our material outstanding indebtedness as of December 31, 2017 is described below.

Notes due 2024

General

On September 21, 2017, we issued US$425.0 million aggregate principal amount of senior secured notes due 2024. The Notes due 2024 mature on September 21, 2024 and bear interest at a fixed rate of 6.50% and a yield of 6.50% per year. Interest on the Notes due 2024 is payable semi-annually in arrears on March 21 and September 21 of each year.

Ranking

The Notes due 2024 constitute senior unsubordinated obligations of GeoPark Limited, secured by a first lien on the Collateral (as described below). The Notes due 2024 rank equally in right of payment with all existing and future senior obligations of GeoPark Limited (except those obligations preferred by operation of Bermuda law, including without limitation labor and tax claims); rank senior to all unsecured debt of GeoPark Limited to the extent of the value of the Collateral; rank senior in right of payment to all existing and future subordinated indebtedness of GeoPark Limited; and rank effectively junior to any future secured obligations of GeoPark Limited and its subsidiaries with a security interest on assets not constituting Collateral, in each case, to the extent of the value of the collateral securing such obligations.

Collateral

The notes are secured by a first-priority perfected security interest in certain collateral (the "Collateral"), which consists of 80% of the equity interests of each of GeoPark Chile and GeoPark Colombia.

Optional redemption

We may, at our option, redeem all or part of the Notes due 2024, at the redemption prices, expressed as percentages of principal amount, set forth below, plus accrued and unpaid interest thereon (including additional amounts), if any, to the applicable redemption date, if redeemed during the 12-month period beginning on September 21 of the years indicated below:

Year	Percentage
2021	103.250%
2022	101.625%
2023 and after	100.000%

Change of control

Upon the occurrence of certain events constituting a change of control, we are required to make an offer to repurchase all outstanding Notes due 2024, at a purchase price equal to 101% of the principal amount thereof plus any accrued and unpaid interest (including any additional amounts payable in respect thereof) thereon to the date of purchase. If holders of not less than 90% in aggregate principal amount of the outstanding Notes due 2024 validly tender and do not withdraw such notes and we repurchase all such notes, we may redeem the Notes due 2024 that remain outstanding following such purchase at a price in cash equal to 101% of the principal amount thereof plus accrued and unpaid interest to but excluding the date of such redemption.

Covenants

The Notes due 2024 contain customary covenants, which include, among others, limitations on the incurrence of debt and disqualified or preferred stock, restricted payments (including restrictions on our ability to pay dividends), incurrence of liens, guarantees of additional indebtedness, the ability of certain subsidiaries to pay dividends, asset sales, transactions with affiliates, engaging in certain businesses and merger or consolidation with or into another company.

In the event the Notes due 2024 receive investment-grade ratings from at least two of the following rating agencies, Standard & Poor's, Moody's and Fitch, and no default has occurred or is continuing under the indenture governing the Notes due 2020, certain of these restrictions, including, among others, the limitations on incurrence of debt and disqualified or preferred stock, restricted payments (including restrictions on our ability to pay dividends), the ability of certain subsidiaries to pay dividends, asset sales and certain transactions with affiliates will no longer be applicable.

The indenture governing our Notes due 2024 includes incurrence test covenants that provide, among other things, that, the net debt to EBITDA ratio should not exceed (i) 3.50 until September 21, 2019, (ii) 3.25 from September 21, 2019 to September 21, 2021, and (iii) 3.00 thereafter until maturity, and the EBITDA to interest ratio should exceed (i) 2.00 until September 21, 2019, (ii) 2.25 from September 21, 2019 to September 21, 2021 and (iii) 2.50 thereafter until maturity. Failure to comply with the incurrence test covenants does not trigger an event of default. However, this situation may limit our capacity to incur additional indebtedness, as specified in the indenture governing the Notes due 2024, other than certain categories of permitted debt. We must test incurrence covenants before incurring additional debt or performing certain corporate actions including but not limited to making dividend payments, restricted payments and others (in each case with certain specific exceptions).

Events of default

Events of default under the indenture governing the Notes due 2024 include: the nonpayment of principal when due; default in the payment of interest, which continues for a period of 30 days; failure to make an offer to purchase and thereafter accept tendered notes following the occurrence of a change of control or as required by certain covenants in the indenture governing the Notes due 2024; the notes, or the security documents in relation thereto that continues for a period of 60 consecutive days after written notice; cross payment default relating to debt with a principal amount of US$30.0 million or more, and cross-acceleration default following a judgment for US$30.0 million or more; bankruptcy and insolvency events; invalidity or denial or disaffirmation of a guarantee of the notes; and failure to maintain a perfected security interest in any collateral having a fair market value in excess of US$15.0 million, among others. The occurrence of an event of default would permit or require the principal of and accrued interest on the Notes due 2024 to become or to be declared due and payable.

Banco de Chile

During December 2015, we entered into a loan agreement with Banco de Chile for US$7.0 million to finance the start-up of the new Ache gas field in the Fell Block. The interest rate applicable to this loan is LIBOR plus 2.35% per year. The interest and the principal have been paid on a monthly basis with a 6-month grace period and final maturity on December 2017.

BCI Loan

During February 2016, we executed a loan agreement with Banco de Crédito e Inversiones (BCI) to finance the acquisition of vehicles for our Chilean operations. 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.

LGI Line of Credit

As of December 31, 2017, the aggregate outstanding amount under the LGI Line of Credit was US$31.2 million. This corresponds to advanced cash call payments granted by LGI to GeoPark Chile for financing Chilean operations in our Tierra del Fuego blocks. The maturity of this balances is July 2020 and the applicable interest rate is 8% per year.

See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Agreements with LGI."

Rio das Contas Credit Facility

We financed our Rio das Contas acquisition in part through our Brazilian subsidiary's entrance into a US$70.5 million credit facility (the "Rio das Contas Credit Facility") with Itaú BBA International plc, which was secured by the benefits GeoPark receives under the Purchase and Sale Agreement for Natural Gas with Petrobras. The loan was fully repaid in September 2017.

Other Agreements

In December 2015, we entered into an offtake and prepayment agreement with Trafigura under which we sell and deliver a portion of our Colombian crude oil production. Pricing will be determined by future spot market prices, net of transportation costs. The agreement also provides us with prepayment of up to US$100 million from Trafigura. Funds committed will be made available to us upon request and will be repaid by us on a monthly basis through future oil deliveries over the period of the contract, which is 2.5 years, including a 6-month grace period. According to the terms of the prepayment agreement, we are required to pay interest of LIBOR plus 5% per year on outstanding amounts. In addition, under the prepayment agreement, we are required to maintain certain coverage ratios linking: (i) future payments to the value of estimated future oil deliveries (net of transportation discounts) during the term of the offtake agreement and (ii) collections to payments within specified periods, with the possibility of delivering additional volumes to meet such ratios in the upcoming 3-month period. As of March 31, 2018, outstanding amounts related to the prepayment agreement amount to US$7.5 million.

C. Research and development, patents and licenses, etc.

See "Item 4. Information on the Company——B. Business Overview" and "Item 4. Information on the Company—B. Business Overview—Title to Properties."

D. Trend information

For a discussion of Trend information, see "—A. Operating Results—Factors affecting our results of operations" and "Item 4. Information on the Company –B. Business Overview—2018 Strategy and Outlook."

E. Off-balance sheet arrangements

We did not have any off-balance sheet arrangements as of December 31, 2017 or as of December 31, 2016.

F. Tabular disclosure of contractual obligations

In accordance with the terms of our concessions, we are required to pay royalties in connection with our crude oil and natural gas production. See Note 32(a) to our Consolidated Financial Statements.

The table below sets forth our committed cash payment obligations as of December 31, 2017.

	Total	Less than one year	One to three years (in thousands of US$)	Three to five years	More than five years
Debt obligations[(1)]	618,455	27,693	55,262	55,250	480,250
Operating lease obligations[(2)]	40,750	32,180	5,777	2,793	—
Pending investment commitments[(3)]	53,791	31,338	22,453	—	—
Asset retirement obligations	38,075	—	—	—	38,075
Total contractual obligations	**751,071**	**91,211**	**83,492**	**58,043**	**518,325**

(1) Refers to principal and interest undiscounted cash flows. Interest payment breakdown included in Debt Obligations is as follows (i) less than one year: US$27.7 million; one to three years: US$55.3 million and three to five years: US$55.3 million. At December 31, 2017, outstanding long-term borrowings were issued at fixed rates. See Note 3: "Interest rate risk" to our Consolidated Financial Statements.
(2) Reflects the future aggregate minimum lease payments under non-cancellable operating lease agreements.
(3) Includes capital commitments in Isla Norte, Campanario and Flamenco Blocks in Chile, rounds 11, 12 and 13 concessions in Brazil, three blocks in Argentina and the Llanos 32, VIM-3, and Llanos 34 Blocks in Colombia. See "Item 4. Information on the Company—B. Business Overview—Our operations" and Note 32(b) to our Consolidated Financial Statements.

G. Safe harbor
See "Forward-Looking Statements."

ITEM 6. DIRECTORS, SENIOR MANAGEMENT AND EMPLOYEES

A. Directors and senior management

Board of directors
Our board of directors is currently composed of seven members. At every annual general meeting, one-third of the Directors retire from office. Our Directors can hold office for such term as the Shareholders may determine or, in the absence of such determination, until the next annual general meeting or until their successors are elected or appointed or their office is otherwise vacated. The Directors whose term has expired may offer themselves for re-election at each election of Directors. The term for the current Directors expires on the date of our next annual shareholders' meeting, to be held in 2018.

The current members of the board of directors were appointed at our annual general meeting held on July 19, 2017. Two previously elected members, Mr. Peter Ryalls and Mr. Michael D. Dingman, passed away following the 2017 annual general meeting, generating two vacancies on our board of directors. The table below sets forth certain information concerning our current board of directors. All ages are as of March 31, 2018.

Name	Position	Age	At the Company since
Gerald E. O'Shaughnessy	Chairman and Director	69	2002
James F. Park	Chief Executive Officer, Deputy Chairman and Director	62	2002
Carlos A. Gulisano (3)	Director	67	2010
Juan Cristóbal Pavez (1)(2)	Director	47	2008
Robert Bedingfield (1)(2)	Director	69	2015
Pedro E. Aylwin Chiorrini	Director, Director of Legal and Governance, Corporate Secretary	58	2003
Jamie B. Coulter (2)	Director	77	2017

(1) Member of the Audit Committee.
(2) Independent director under SEC Audit Committee rules.
(3) Carlos Gulisano joined the Company in 2002 as an advisor.

Biographical information of the current members of our Board of Directors is set forth below. Unless otherwise indicated, the current business addresses for our directors is Nuestra Señora de los Ángeles 179, Las Condes, Santiago, Chile.

Gerald E. O'Shaughnessy has been our Chairman and a member of our board of directors since he co-founded the company in 2002. Following his graduation from the University of Notre Dame with degrees in government (1970) and law (1973), Mr. O'Shaughnessy was engaged in the practice of law in Minnesota. Mr. O'Shaughnessy has been active in the oil and gas business over his entire business career, starting in 1976 with Lario Oil and Gas Company, where he served as Senior Vice President and General Counsel. He later formed The Globe Resources Group, a private venture firm whose subsidiaries provided seismic acquisition and processing, well rehabilitation services, sophisticated logistical operations and submersible pump works for Lukoil and other companies active in Russia during the 1990s. Mr. O'Shaughnessy is also founder and owner of BOE Midstream, LLC, which owns and operates the Bakken Oil Express, a crude by rail transloading and storage terminal in North Dakota, serving oil producers and marketing companies in the Bakken Shale Oil play. Over the past 25 years, Mr. O'Shaughnessy has also founded and operated companies engaged in banking, wealth management products and services, investment desktop software, computer and network security, and green clean technology, as well as other venture investments, Mr. O'Shaughnessy has also served on a number of non-profit boards of directors, including the Board of Economic Advisors to the Governor of Kansas, the I.A. O'Shaughnessy Family Foundation, the Wichita Collegiate School, the Institute for Humane Studies, The East West Institute and The Bill of Rights Institute, the Timothy P. O'Shaughnessy Foundation and is a member of the Intercontinental Chapter of Young Presidents Organization and World Presidents' Organization.

James F. Park has served as our Chief Executive Officer and as a member of our board of directors since co-founding the Company in 2002. He has over 40 years of experience in all phases of the upstream oil and gas business, with a strong background in the acquisition, implementation and management of international projects and teams in North America, South America, Asia, Europe and the Middle East. He received a bachelor of science degree in geophysics from the University of California at Berkeley and previously worked as a research scientist in earthquake and tectonic at the University of Texas. In 1978, Jim helped pioneer the development of commercial oil and gas production in Central America with Basic Resources, an oil and gas exploration company, in Guatemala. He remained a member of the board of directors of Basic Resources International Limited until the company was sold in 1997. Mr. Park is also a member of the board of directors of Energy Holdings and has also been involved in oil and gas projects in California, Louisiana, Argentina, Yemen and China. Mr. Park is a member of the AAPG and SPE and has lived in Latin America since 2002.

Carlos Gulisano has been a member of our board of directors since June 2010. Dr. Gulisano holds a bachelor's degree in geology, a post-graduate degree in petroleum engineering and a PhD in geology from the University of Buenos Aires and has authored or co-authored over 40 technical papers. He is a former adjunct professor at the Universidad del Sur, a former thesis director at the University of La Plata, and a former scholarship director at CONICET, the national technology research council, in Argentina. Dr. Gulisano is a respected leader in the fields of petroleum geology and geophysics in South America and has over 40 years of successful exploration, development and management experience in the oil and gas industry. In addition to serving as an advisor to GeoPark since 2002 and as Managing Director from February 2008 until June 2010, Dr. Gulisano has worked for YPF, Petrolera Argentina San Jorge S.A. and Chevron San Jorge S.A. and has led teams credited with significant oil and gas discoveries, including those in the Trapial field in Argentina. He has worked in Argentina, Bolivia, Peru, Ecuador, Colombia, Venezuela, Brazil, Chile and the United States. Mr. Gulisano is also an independent consultant on oil and gas exploration and production.

Juan Cristóbal Pavez has been a member of our board of directors since August 2008. He holds a degree in commercial engineering from the Pontifical Catholic University of Chile and an MBA from the Massachusetts Institute of Technology. He has worked as a research analyst at Grupo CB and later as a portfolio analyst at Moneda Asset Management. In 1998, he joined Santana, an investment company, as Chief Executive Officer, where he focused mainly on investments in capital markets and real estate. While at Santana, he was appointed Chief Executive Officer of Laboratorios Andrómaco, one of Santana's main assets. In 1999, Mr. Pavez co-founded Eventures, an internet company. Since 2001, he has served as Chief Executive Officer at Centinela, a company with a diversified global portfolio of investments. Mr. Pavez is also a board member of Grupo Security, Vida Security and Hidroeléctrica Totoral. Over the last few years he has been a board member of several companies, including Quintec, Enaex, CTI and Frimetal.

Robert Bedingfield has been a member of our board of directors since March 2015. He holds a degree in Accounting from the University of Maryland and is a Certified Public Accountant. Until his retirement in June 2013, he was one of Ernst & Young's most senior Global Lead Partners with more than 40 years of experience, including 32 years as a partner in Ernst & Young's accounting and auditing practices, as well as serving on Ernst & Young's Senior Governing Board. He has extensive experience serving Fortune 500 companies; including acting as Lead Audit Partner or Senior Advisory Partner for Lockheed Martin, AES, Gannett, General Dynamics, Booz Allen Hamilton, Marriott and the US Postal Service. Since 2000, Mr. Bedingfield has been a Trustee, and at times an Executive Committee Member, and the Audit Committee Chair of the University of Maryland at College Park Board of Trustees. Mr. Bedingfield served on the National Executive Board (1995 to 2003) and National Advisory Council (since 2003) of the Boy Scouts of America. Since 2013, Mr. Bedingfield has also served as Board Member and Chairman of the Audit Committee of NYSE-listed Science Applications International Corp (SAIC).

Pedro E. Aylwin Chiorrini has served as a member of our board of directors since July 2013 and as our Director of Legal and Governance since April 2011. From 2003 to 2006, Mr. Aylwin worked for us as an advisor on governance and legal matters. Mr. Aylwin holds a degree in law from the Universidad de Chile and an LLM from the University of Notre Dame. Mr. Aylwin has extensive experience in the natural resources sector. Mr. Aylwin is also a partner at the law firm Aylwin, Mendoza, Luksic, Valencia Abogados in Santiago, Chile, where he represented mining, chemical and oil and gas companies in numerous transactions. From 2006 until 2011, he served as Lead Manager and General Counsel at BHP Billiton, Base Metals, where he was in charge of legal and corporate governance matters on BHP Billiton's projects, operations and natural resource assets in South America, North America, Asia, Africa and Australia.

Jamie B. Coulter is a well-respected businessman, who has spearheaded the growth of a variety of businesses in diverse sectors. He holds a business degree from Wichita State University and is a graduate of the Stanford University Executive Program. Mr. Coulter currently serves as Managing Member of Coulter Enterprises LLC., a private investment firm. Mr. Coulter has been an investor in GeoPark since 2006. Mr. Coulter has more than 46 years of experience in the food retail and restaurant business, serving as Chief Executive Officer of Lone Star Steakhouse & Saloon and having developed and operated Pizza Hut and Kentucky Fried Chicken restaurants. Mr. Coulter is a former Restaurants & Institutions CEO of the year. Mr. Coulter has operating and investment experience in the oil and gas business, including the founding of Sunburst Exploration, a US upstream oil and gas company that he built throughout the 1980s and sold in 1994. Mr. Coulter also has been an active participant as an investor in North American shale plays during the last ten years. Mr. Coulter currently serves as a Director of the Federal Law Enforcement Foundation and is a member of the Board of Trustees for HCA Wesley Medical Center, and has previously served on a number of boards of directors, including as a Director of Jimmy Johns LLC, Chairman of the Board of the International Pizza Hut Franchise Holders' Association, a member of the Board of Advisors of The Wichita State University Center for Entrepreneurship and a member of the Board of Trustees for the University of Kansas School of Business, among others.

Executive officers

Our executive officers are responsible for the management and representation of our company. The table below sets forth certain information concerning our executive officers. All ages are as of March 31, 2018.

Name	Position	Age	At the Company since
James F. Park	Chief Executive Officer and Director	62	2002
Andrés Ocampo	Chief Financial Officer	40	2010
Pedro E. Aylwin Chiorrini	Director, Director of Legal and Governance, and Corporate Secretary	58	2003
Augusto Zubillaga	Chief Operating Officer	48	2006
Alberto Matamoros	Director for Argentina, Brazil and Chile	46	2014
Barbara Bruce	Director for Peru	61	2017
Marcela Vaca	Director for Colombia	49	2012
Carlos Murut	Director of Development	61	2006
Salvador Minniti	Director of Exploration	63	2007
Horacio Fontana	Director of Drilling	60	2008
Agustina Wisky	Director of Business Management	41	2002
Guillermo Portnoi	Director of New Business	42	2006
Stacy Steimel	Director of Shareholder Value	58	2017

Biographical information of the members of our executive officers is set forth below. Unless otherwise indicated, the current business addresses for our executive officers is Nuestra Señora de los Ángeles 179, Las Condes, Santiago, Chile.

Andrés Ocampo has served as our Chief Financial Officer since November 2013. He previously served as our Director of Growth and Capital (from January 2011 through October 2013), and has been with our company since July 2010. Mr. Ocampo graduated with a degree in Economics from the Universidad Católica Argentina. He has more than 16 years of experience in business and finance. Before joining our company, Mr. Ocampo worked at Citigroup and served as Vice President Oil & Gas and Soft Commodities at Crédit Agricole Corporate & Investment Bank.

Augusto Zubillaga has served as our Chief Operating Officer since May 2015. He previously served in other management positions throughout the Company including as Operations Director, Argentina Director and Production Director. He previously served as our Production Director. He is a petroleum engineer with more than 23 years of experience in production, engineering, well completions, corrosion control, reservoir management and field development. He has a degree in petroleum engineering from the Instituto Tecnológico de Buenos Aires. Prior to joining our company, Mr. Zubillaga worked for Petrolera Argentina San Jorge S.A. and Chevron San Jorge S.A. At Chevron San Jorge S.A., he led multi-disciplinary teams focused on improving production, costs and safety, and was the leader of the Asset Development Team, which was responsible for creating the field development plan and estimating and auditing the oil and gas reserves of the Trapial field in Argentina. Mr. Zubillaga was also part of a Chevron San Jorge S.A. team that was responsible for identifying business opportunities and working with the head office on the establishment of best business practices. He has authored several industry papers, including papers on electrical submersible pump optimization, corrosion control, water handling and intelligent production systems.

Alberto Matamoros has been our Director for Argentina, Brazil, Chile and Peru since March 2016 and Director for Chile since January 2015. He is an industrial engineer and has an MBA, with more than 20 years of experience in the Oil & Gas industry. He started his career in the Argentinian oil company ASTRA, as a Production Engineer of La Ventana-Vizcacheras Block in the province of Mendoza (1997-2000). He then joined Chevron, where he worked as a Production Engineer in El Trapial Block in the province of Neuquén for three years. Later, he became a Field Engineering Manager, also for three years, in Buenos Aires, and then moved to Kern County, California, to lead the production team. His experience in Chevron enabled him to manage different technical and administrative teams, designing and executing working plans focused in the optimization of resources. In 2014, he joined GeoPark to be part of the Corporate Operation team before being selected as the new Director for Chile. Matamoros holds a degree in Industrial Engineering from the Universidad Nacional del Sur and an MBA in IAE, from the Business School of Universidad Austral of Buenos Aires, Argentina.

Barbara Bruce has been our Director for Peru since June 2017. Ms. Bruce holds a degree in Geology from the Universidad Nacional de Ingeniería, Lima, Peru, a Master's degree in Reservoirs from Colorado School of Mines, USA and an MBA from Universidad Adolfo Ibañez, USA/Chile. Before joining GeoPark, she previously worked with Occidental Petroleum in different international operations, including in the Caño Limon field in Colombia and the Dhurnal and Bhangali gas fields in Pakistan. Ms. Bruce later worked as deputy President of an offshore operation by Petrotech Peruana, joined Hunt Oil and as General Manager of Peru LNG, leading the construction and startup of operation of Peru´s first LNG plant and managed the exploration venture of Hunt Oil in Madre de Dios, Peru.

Marcela Vaca has been our Director for Colombia since August 2012. Ms. Vaca holds a degree in law from Pontificia Universidad Javeriana in Bogotá, Colombia, a Master's Degree in commercial law from the same university and an LLM from Georgetown University. She has served in the legal departments of a number of companies in Colombia, including Empresa Colombiana de Carbon Ltda (which later merged with INGEOMINAS), and from 2000 to 2003, she served as Legal and Administrative Manager at GHK Company Colombia. Prior to joining our company in 2012, Ms. Vaca served for nine years as General Manager of the Hupecol Group where she was responsible for supervising all areas of the company as well as managing relationships with Ecopetrol, ANH, the Colombian Ministry of Mines and Energy, the Colombian Ministry of Environment and other governmental agencies. At the Hupecol Group, Ms. Vaca was also involved in the structuring of the Hupecol Group's asset development and sales strategy.

Carlos Murut has been our Director of Development since January 2012. He previously served as our Development Manager. Mr. Murut holds a master's degree in petroleum geology from the University of Buenos Aires where he also undertook postgraduate studies in reservoir engineering, specializing in field exploitation. He also completed a Business Management Development Program at Austral University. Mr. Murut has over 40 years of experience working for international and major oil companies, including YPF S.A., Tecpetrol S.A., Petrolera Argentina San Jorge S.A. and Chevron San Jorge S.A.

Salvador Minniti has been our Director of Exploration since January 2012. He previously served as our Exploration Manager. He holds a bachelor degree in geology from National University of La Plata and has a graduate degree from the Argentine Oil and Gas Institute in oil geology. Mr. Minniti has over 35 years of experience in oil exploration and has worked with YPF S.A., Petrolera Argentina San Jorge S.A. and Chevron Argentina.

Horacio Fontana has been our Corporate Drilling Manager since March 2012. He previously served as our Engineer Manager. He holds a degree in civil engineering from Rosario National University and is also a graduate from the Argentine Oil and Gas Institute, National University of Buenos Aires, with a specialty in oilfield exploitation and an extensive background in drilling operations. He has recently taken part in a Management Development Program at IAE Business School of Austral University. Mr. Fontana has over 31 years of drilling experience in major Argentine companies such as YPF S.A., Petrolera Argentina San Jorge and Chevron.

Agustina Wisky has worked with our Company since it was founded in November 2002, and has served as our Director of People since 2012 until December 2016 and is currently our Director of Business Management. Mrs. Wisky is a public accountant, and also holds a degree in human resources from the Universidad Austral—IAE. She has 15 years of experience in the oil industry. Before joining our company, Mrs. Wisky worked at AES Gener and PricewaterhouseCoopers.

Guillermo Portnoi has worked with our Company since June 2006 and has been our Director of Business Management since May 2015 until December 2016 and is currently our Director of New Business. Previously, he also served as our Director of Administration and Finance. Mr. Portnoi is a public accountant and holds an MBA from Universidad Austral—IAE. He has more than 14 years of experience in the oil industry. Before joining our company, Mr. Portnoi worked at Pluspetrol, Río Alto and PricewaterhouseCoopers, where he counted several major oil companies as his clients.

Stacy Steimel joined GeoPark in February 2017 as our Shareholder Value Director. Mrs. Steimel has more than 20 years of experience in the financial sector as Fund Manager and subsequently as regional CEO for PineBridge Investments, ex-AIG Investments in Latin America. Before AIG, Mrs. Steimel held positions in the US Treasury Department and at the InterAmerican Development Bank. She holds an MBA from the Pontificia Universidad Católica de Chile, an MA in Latin American Studies from the University of Texas at Austin and a BA from the College of William and Mary.

B. Compensation

Executive compensation

For the year ended December 31, 2017, we accrued or paid approximately US$4.5 million, in the aggregate, to the members of our board of directors (including our executive directors) for their services in all capacities. During this same period, we accrued or paid approximately US$7.8 million, in the aggregate, to the members of our senior management (excluding our executive directors) for their services in all capacities. An amount of US$0.9 million corresponds to the accrual or payment for discretionary bonus cash payments granted to the Company's executive directors based on the Company's performance in 2017. Gerald E. O'Shaughnessy, James F. Park and Pedro E. Aylwin Chiorrini are our executive directors.

Executive Director Contracts

It is our current policy that executive directors enter into indefinite term contracts with the Company that may be terminated at any time by either party subject to certain notice requirements.

Gerald E. O'Shaughnessy has entered into a service contract with the Company to act as Chairman at an annual salary of US$400,000. James F. Park has entered into a service contract with the Company to act as Chief Executive Officer at an annual salary of US$800,000. They each also received equity awards described below under "Equity Incentive Compensation." Our agreements with Mr. O'Shaughnessy and Mr. Park contain covenants that restrict them, for a period of 12 months following termination of employment, from soliciting senior employees of the Company and, for a period of six months following a termination of employment, from competing with the Company.

Pedro E. Aylwin Chiorrini, who was appointed as an executive director in July 2013, has entered into a service contract with the Company to act as Director of Legal and Governance, and as such has decided to forego his director fees. He instead received in 2017 a salary of US$0.3 million and bonus of US$0.1 million for his services as a member of senior management.

The following chart summarizes payments made to our executive directors for the year ended December 31, 2017:

		Cash payment
	Executive Directors' Fees	Bonus
Gerald E. O'Shaughnessy	US$400,000	—
James F. Park	US$800,000	US$800,000
Pedro E. Aylwin Chiorrini	—	—

Bonus payments above were approved by the Compensation Committee on March, 16 2017 and reflect awards for previous years' performance including the discretionary bonus payments made based on our performance in 2016.

Non-Executive Director Contracts

The current annual fees paid to our non-executive Directors correspond to US$80,000 to be settled in cash and US$100,000 to be settled in stock, 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 applies. A Director who serves as a member of any Board Committees receives an annual fee of US$10,000. Total payment due shall be calculated on an aggregate basis for Directors serving in more than one Committee. The Chairman fee is not added to the member's fee while serving for the same Committee. Payments of Chairmen and Committee members' fees are made quarterly in arrears and settled in cash only.

The following chart summarizes payments made to our non-executive directors for the year ended December 31, 2017.

Non-Executive Director	Non-Executive Directors' Fees in US$	Fees paid in Common Shares [(1)]
Juan Cristóbal Pavez (2)	110,000	15,408
Carlos Gulisano (3)	110,000	15,408
Robert Bedingfield (4)	102,500	15,408
Peter Ryalls(5)	115,000	9,388
Michael D. Dingman(5)	46,667	8,853
Jamie B. Coulter	50,000	6,020

[(1)] The numbers in this column are equal to 70,485 Common Shares (which amount equals to US$454,058).
[(2)] Compensation Committee Chairman and Member of Audit Committee.
[(3)] Technical Committee Chairman and Member of Compensation Committee.
[(4)] Audit Committee Chairman and Member of Nomination Committee.
[(5)] Mr. Peter Ryalls and Mr. Michael D. Dingman passed away following the 2017 annual general meeting.

Pension and retirement benefits

We do not maintain any defined benefit pension plans or any other retirement programs for our employees or directors.

Equity Incentive Compensation

Performance-Based Employee Long-Term Incentive Program

In November 2007, our shareholders voted to authorize the board of directors to use up to a maximum of 12% of our issued share capital for the purposes of granting equity awards to our employees and other service providers. The shareholders also authorized the board of directors to adopt programs for this purpose and to determine specific conditions and broadly defined guidelines for such programs.

Stock Awards Plan

The purpose of the Stock Awards Plan is to align the interests of our management, employees and key advisors with those of shareholders. Under the Stock Awards Plan, the board of directors, or its designee, may award options or stock awards. An option confers the right to acquire a specified number of common shares of the Company at an exercise price equal to the par value of the common shares subject to such an option. A performance share confers a conditional right to acquire a specified number of common shares for zero or nominal consideration, subject to the achievement of performance conditions and other vesting terms.

On December 17, 2014, we registered 3,435,600 shares with the U.S. SEC for shares to be issued under the Stock Awards Plan. The following table sets forth the common share awards granted to our executive directors, management and employees under the Stock Awards Plan commencing in 2008 through March 31, 2018.

Number of underlying common shares outstanding	Grant date	Vesting date	Expiration date
976,211[(1)]	12/15/2008	12/15/2012	12/15/2018
817,600[(1)]	12/15/2010	12/15/2014	12/15/2020
478,000[(1)]	12/15/2011	12/15/2015	12/15/2021
720,000[(2)]	11/23/2012	11/23/2015	11/23/2016
379,500	12/15/2012	12/15/2016	12/15/2022
490,000	12/31/2014	12/31/2017	12/31/2022
1,619,105[(3)]	06/30/2016	06/30/2019	06/30/2026

[(1)] Pedro E. Aylwin Chiorrini holds 40,000 shares of the 2008 award, 25,000 shares of the 2010 award and 12,000 shares of the 2011 award.
[(2)] James F. Park received 450,000 shares of such awards, and Gerald E. O'Shaughnessy received 270,000 shares of such awards.
[(3)] Vesting of these common share awards was subject to the achievement of certain minimum financial and operational targets during a performance period that runs through 2016 to 2018. If such conditions are not achieved as of the vesting date, only the equivalent of one monthly salary will be issued in shares.

Our executive directors, senior management and employees who have received option awards or common share awards under the Stock Awards Plan authorize the Company to deposit any common shares they have received under this plan in our Employee Benefit Trust ("EBT"). The EBT is held to facilitate holdings and dispositions of those common shares by the participants thereof. Under the terms of the EBT, each participant is entitled to receive any dividends we may pay which correspond to their common shares held by the trust, according to instructions sent by the Company to the trust administrator. The trust provides that Mr. James F. Park is entitled to vote all the common shares held in the trust.

Value Creation Plan

On December 10, 2015, the Board of Directors approved a renewal of the VCP for a new period of three years, with new rewards granted on January 1, 2016. Under the current VCP, if as of December 31, 2018, our share price has increased by 12% per year according to the plan conditions, VCP participants (key management) will receive awards with an aggregate value equal to 10% of the excess above the market capitalization threshold generated by this share price (assuming that the share capital of the Company had remained at the same level as applicable at the time of establishment of the VCP: 59,535,614 shares). The awards will vest and be paid in common shares 50% on December 31, 2018, and the remaining 50% on December 31, 2019. As in the previous VCP, the total number of common shares granted pursuant to this plan shall not exceed 5% of the issued share capital of the Company. For further details see Note 30 to our Consolidated Financial Statements.

Non-Executive Director Plan

In August 2014, our Board of Directors adopted the Non-Executive Director Plan in order to grant shares to non-executive directors as part of their compensation program for serving as directors, which was amended and restated in October 2016. In accordance with the resolutions adopted by our board of directors on May 20, 2014, our non-executive directors are paid their quarterly fees in the form of equity awards granted under the Non-Executive Director Plan. Under the Non-Executive Director Plan, the compensation committee may award common shares, restricted share units and other share-based awards that may be denominated or payable in common shares or factors that influence the value of common shares. The maximum number of common shares available for issuance under the Non-Executive Director Plan is 1,000,000 common shares.

Potential dilution resulting from Equity Incentive Compensation Plans

The percentage of total share capital that could be awarded to our directors, management and key employees under the Stock Awards Plan described above would represent approximately 14% of our issued common shares as of December 31, 2017. In accordance with existing equity compensation plans as of the date of this annual report, there are approximately 4.6 million outstanding shares that have been awarded but which have not yet vested, representing approximately 7.5% of the total issued share capital as of December 31, 2017.

C. Board practices

Overview

Our Board of Directors is responsible for establishing our listed company goals, ensuring that the necessary resources are in place to achieve these goals and reviewing our management and financial performance. Our board of directors directs and monitors the company in accordance with a framework of controls, which enable risks to be assessed and managed through clear procedures, lines of responsibility and delegated authority. Our board of directors also has responsibility for establishing our core values and standards of business conduct and for ensuring that these, together with our obligations to our shareholders, are understood throughout the company.

Board composition

Our bye-laws and board resolutions provide that the board of directors consist of a minimum of three and a maximum of nine members. All of our directors were elected at our annual shareholders' meeting held on July 19, 2017. Their term expires on the date of our next annual shareholders' meeting, to be held in 2018. The board of directors meets at least on a quarterly basis.

Committees of our board of directors

Our board of directors has established an Audit Committee, a Compensation Committee, a Nomination Committee, a Technical Committee and a Disclosure Committee. The composition and responsibilities of each committee are described below. Members serve on the Audit Committee for a period of three years. For the Nomination Committee, members serve for a period of one year. For the Compensation Committee, members serve for the same period as their board term. For the Technical Committee and Disclosures Committee, members serve on these committees until their resignation or until otherwise determined by our board of directors. In the future, our board of directors may establish other committees to assist with its responsibilities.

Audit Committee

The Audit Committee is composed of three directors. The current members of the Audit Committee are Mr. Juan Cristóbal Pavez and Mr. Robert Bedingfield (who currently serves as Chairman of the committee). We have determined that Mr. Juan Cristóbal Pavez and Robert Bedingfield are independent, as such term is defined under SEC rules applicable to foreign private issuers. Currently, there is a vacancy created by the passing of Mr. Peter Ryalls on July 25, 2017.

The Audit Committee's responsibilities include: (a) approving our financial statements; (b) reviewing financial statements and formal announcements relating to our performance; (c) assessing the independence, objectivity and effectiveness of our external auditors; (d) making recommendations for the appointment, re-appointment and removal of our external auditors and approving their remuneration and terms of engagement; (e) implementing and monitoring policy on the engagement of external auditors supplying non-audit services to us; (f) obtaining, at our expense, outside legal or other professional advice on any matters within its terms of reference and securing the attendance at its meetings of outsiders with relevant experience and expertise if it considers it necessary; and (g) reviewing our arrangements for our employees to raise concerns about possible wrongdoing in financial reporting or other matters and the procedures for handling such allegations, and ensuring that these arrangements allow proportionate and independent investigation of such matters and appropriate follow-up action.

Compensation Committee

The Compensation Committee is composed of three directors. The current members of the compensation committee are Mr. Juan Cristóbal Pavez (who serves as Chairman of the committee) and Mr. Carlos Gulisano. Currently there is one vacancy created by the passing of Mr. Peter Ryalls on July 25, 2017.

The Compensation Committee meets at least twice a year, and its specific responsibilities include: (a) reviewing and recommending to the board of directors the remuneration policy for the Chief Executive Officer, the Chairman, our executive directors and other members of executive management; (b) reviewing the performance of our executive directors and members of executive management; and (c) reviewing all incentive compensation plans, equity-based plans, and all modifications to such plans as well as administering and granting awards under all such plans and approving plan payouts; and (d) reviewing and making recommendations to the Board with respect to the adoption or modification of executive officer and director share ownership guidelines and monitor compliance with any adopted share ownership guidelines.

Nomination Committee

The Nomination Committee is composed of four directors. The members of the Nomination Committee are Mr. Gerald E. O'Shaughnessy, Mr. James F. Park, Mr. Robert Bedingfield and Mr. Pedro E. Aylwin Chiorrini (who serves as Chairman of the committee).

The Nomination Committee meets at least twice a year and its responsibilities include: (a) reviewing the structure, size and composition of the board of directors and making recommendations to the board of directors in respect of any required changes; (b) identifying, nominating and submitting for approval by the board of directors candidates to fill vacancies on the board of directors as and when they arise; (c) making recommendations to the board of directors with respect to the membership of the Audit Committee and Compensation Committee in consultation with the chairman of each committee, and with respect to the appointment of any director or executive officer or other officer other than the position of the Chairman and Chief Executive Officer and (d) succession planning for directors and senior executives.

Technical Committee

The Technical Committee is composed of three directors along with the Chief Operating Officer. The members of the Technical Committee are Mr. Carlos Gulisano (who serves as Chairman of the committee), Mr. Gerald O´Shaughnessy, Mr. James F. Park and Mr. Augusto Zubillaga.

The Technical Committee's responsibilities include: (a) overseeing the technical studies and evaluations of the Company's properties and proposals to acquire new properties and/or relinquish existing ones as well as reviewing project plans; (b) reviewing the Annual Reserve Report, the Company's environmental programs and their effectiveness and the Company's health and safety program and its effectiveness; and (c) providing a forum for ideas and solutions for the key technical people within the Company.

Disclosure Committee

The Disclosure Committee is composed of Mr. James F. Park, Mr. Andrés Ocampo, and certain other officers or managers per request.

The Disclosure Committee's responsibilities include (a) review and approval of filings with the SEC and press releases, (b) review of presentations to analysts, investors and rating agencies and (c) establishment of disclosure controls and procedures.

Liability insurance

We maintain liability insurance coverage for all of our directors and officers, the level of which is reviewed annually.

D. Employees

As of December 31, 2017, we had 405 employees, representing an increase of 17% from December 31, 2016.

The following table sets forth a breakdown of our employees by geographic segment for the periods indicated.

	Year ended December 31,		
	2017	2016	2015
Colombia	180	146	133
Chile	102	102	106
Brazil	12	10	12
Argentina	92	77	90
Peru	19	10	11
Total	**405**	**345**	**352**

From time to time, we also utilize the services of independent contractors to perform various field and other services as needed. As of December 31, 2017, 37 of our employees were represented by labor unions or covered by collective bargaining agreements. We believe that relations with our employees are satisfactory.

E. Share ownership

As of March 15, 2018, members of our board of directors and our senior management held as a group 20,881,731 of our common shares and 34.5% of our outstanding share capital.

The following table shows the share ownership of each member of our board of directors and senior management as of March 15, 2018.

Shareholder	Common shares	Percentage of outstanding common shares
James F. Park(1)	7,891,269	13.0%
Gerald E. O'Shaughnessy(2)	7,213,316	11.9%
Juan Cristóbal Pavez(3)	2,964,162	4.9%
Carlos Gulisano	193,327	0.3%
Pedro E. Aylwin Chiorrini	220,859	0.4%
Robert Bedingfield	82,495	0.1%
Jamie B. Coulter	1,517,587	2.5%
Augusto Zubillaga	*	*
Alberto Matamoros	*	*
Marcela Vaca	*	*
Barbara Bruce	*	*
Carlos Murut	*	*
Salvador Minniti	*	*
Stacy Steimel	*	*
Horacio Fontana	*	*
Agustina Wisky	*	*
Guillermo Portnoi	*	*
Andrés Ocampo	*	*
Sub-total senior management ownership of less than 1%	**798,716**	**1.3%**
Total	**20,881,731**	**34.5%**

* Indicates ownership of less than 1% of outstanding common shares.

(1) Held by Energy Holdings, LLC, which is controlled by James F. Park, a member of our Board of Directors. The number of common shares held by Mr. Park does not reflect the 1,533,927 common shares held as of March 15, 2018 in the employee benefit trust described under "Item 6. Directors, Senior Management and Employees—B. Compensation— Stock Awards Plan." 1,073,201 of these common shares have been pledged pursuant to lending arrangements. The information set forth above is based solely on the disclosure set forth in Mr. Park's most recent Schedule 13G filed with the SEC on February 13, 2018.

(2) Held directly and indirectly through GP Investments LLP, GPK Holdings LLC and other investment vehicles. 6,975,957 of these common shares have been pledged pursuant to lending arrangements. The information set forth above is based solely on the disclosure set forth in Mr. O'Shaughnessy's most recent Schedule 13G filed with the SEC on February 13, 2018.

(3) Held through Socoservin Overseas Ltd, which is controlled by Juan Cristóbal Pavez. The common shares reflected as being held by Mr. Pavez include 86,358 common shares held by him personally.

ITEM 7. MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

A. Major shareholders

The following table presents the beneficial ownership of our common shares as of March 15, 2018:

Shareholder	Common shares	Percentage of outstanding common shares
James F. Park[(1)]	7,891,269	13.0%
Gerald E. O'Shaughnessy[(2)]	7,193,316	11.9%
Manchester Financial Group, L.P.[(3)]	5,103,439	8.4%
IFC Equity Investments[(4)]	2,998,633	4.9%
Juan Cristóbal Pavez[(5)]	2,964,162	4.9%
Other shareholders	34,439,653	56.8%
Total	**60,606,787**	**100.0%**

(1) Held by Energy Holdings, LLC, which is controlled by James F. Park, a member of our Board of Directors. The number of common shares held by Mr. Park does not reflect the 1,533,927 common shares held as of March 15, 2018 in the employee benefit trust described under "Item 6. Directors, Senior Management and Employees—B. Compensation— Stock Awards Plan." 1,073,201 of these common shares have been pledged pursuant to lending arrangements. The information set forth above and listed in the table is based solely on the disclosure set forth in Mr. Park's most recent Schedule 13G filed with the SEC on February 13, 2018.
(2) Held directly and indirectly through GP Investments LLP, GPK Holdings LLC and other investment vehicles. 6,975,957 of these common shares have been pledged pursuant to lending arrangements. The information set forth above and listed in the table is based solely on the disclosure set forth in Mr. O'Shaughnessy's most recent Schedule 13G filed with the SEC on February 13, 2018.
(3) Held directly and indirectly through Manchester Financial Group, L.P., Manchester Financial Group, Inc., Douglas F. Manchester and Papa Doug Trust u/t/d/ January 11, 2010. This information is based solely on the disclosure set forth in Manchester Financial Group, L.P.'s most recent Schedule 13G filed with the SEC on February 8, 2017.
(4) IFC Equity Investments voting decisions are made through a portfolio management process which involves consultation from investment officers, credit officers, managers and legal staff. This information is based solely on the disclosure set forth in the IFC's most recent Schedule 13G/A filed with the SEC on March 23, 2018.
(5) Held through Socoservin Overseas Ltd, which is controlled by Juan Cristóbal Pavez. The common shares reflected as being held by Mr. Pavez include 86,358 common shares held by him personally.

Principal shareholders do not have any different or special voting rights in comparison to any other common shareholder.

According to our transfer agent, as of February 28, 2018, we had 22 registered shareholders, out of which 6 are registered as U.S. shareholders. Since some of the shares are held by nominees, the number of shareholders may not be representative of the number of beneficial owners.

B. Related party transactions

We have entered into the following transactions with related parties:

LGI Chile Shareholders' Agreements

In 2010, we formed a strategic partnership with LGI to acquire and develop jointly upstream oil and gas projects in Latin America. In 2011, LGI acquired a 20% equity interest in GeoPark Chile and a 14% equity interest in GeoPark TdF, for a total consideration of US$148.0 million, plus additional equity funding of US$18.0 million through 2014. On May 20, 2011, in connection with LGI's investment in GeoPark Chile, we and LGI entered into the LGI Chile Shareholders' Agreements, setting forth our and LGI's respective rights and obligations in connection with LGI's investment in our Chilean oil and gas business. Specifically, the LGI Chile Shareholders' Agreements provide that the boards of each of GeoPark Chile and GeoPark TdF will consist of four directors; as long as LGI holds at least 5% of the voting shares of GeoPark Chile or GeoPark TdF, as applicable, LGI has the right to elect one director and such director's alternate, while the remaining directors, and alternates, are elected by us. Additionally, the agreements require the consent of LGI or its appointed director in order for GeoPark Chile or GeoPark TdF, as applicable, to be able to take certain actions, including, among others: making any decision to terminate or permanently or indefinitely suspend operations in or surrender our blocks in Chile (other than as required under the terms of the relevant CEOP for such blocks); selling our blocks in Chile to our affiliates; making any change to the dividend, voting or other rights that would give preference to or discriminate against the shareholders of these companies; entering into certain related party transactions; and creating a security interest over our blocks in Chile (other than in connection with a financing that benefits our Chilean subsidiaries). The LGI Chile Shareholders' Agreements also provide that: (i) if LGI or either Agencia or GeoPark Chile decides to sell its shares in GeoPark Chile or GeoPark TdF, as applicable, the transferring shareholder must make an offer to sell those shares to the other shareholder before selling them to a third party; and (ii) any sale to a third party is subject to tag-along and drag-along rights, and the non-transferring shareholder has the right to object to a sale to the third-party if it considers such third-party to be not of a good reputation or one of our direct competitors. We and LGI also agreed to vote our common shares or otherwise cause GeoPark Chile or GeoPark TdF, as applicable, to declare dividends only after allowing for retentions to meet anticipated future investments, costs and obligations. See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Agreements with LGI—LGI Chile Shareholders' Agreements."

LGI Colombia Agreements

On December 18, 2012, we, Agencia, GeoPark Colombia and LGI entered into the LGI Colombia Shareholders' Agreement and a subscription share agreement, pursuant to which LGI acquired a 20% interest in GeoPark Colombia SAS. Further, on January 8, 2014, following an internal corporate reorganization of our Colombian operations, GeoPark Colombia Coöperatie U.A. and GeoPark Latin America entered into a new members' agreement with LGI (the "LGI Colombia Members' Agreement"), that sets out substantially similar rights and obligations to the LGI Colombia Shareholders' Agreement in respect of our oil and gas business in Colombia. We refer to the LGI Colombia Shareholders' Agreement and the LGI Colombia Members' Agreement collectively as the LGI Colombia Agreements. The LGI Colombia Members' Agreements provide that the board of GeoPark Colombia Coöperatie U.A. will consist of four directors; as long as LGI holds at least 14% of GeoPark Colombia SAS, LGI has the right to elect one director and such director's alternate, while the remaining directors, and alternates, are elected by us. Additionally, the LGI Colombia Agreements require the consent of LGI or the LGI appointed director for GeoPark Colombia SAS to be able to take certain actions, including, among others: making any decision to terminate or permanently or indefinitely suspend operations in or surrender our blocks in Colombia (other than as required under the terms of the relevant concessions for such blocks); creating a security interest over our blocks in Colombia; approving of GeoPark Colombia SAS' annual budget and work programs and the mechanisms for funding any such budget or program; entering into any borrowings other than those provided in an approved budget or incurred in the ordinary course of business to finance working capital needs; granting any guarantee or indemnity to secure liabilities of parties other than those of our Colombian subsidiaries; changing the dividend, voting or other rights that would give preference to or discriminate against the shareholders of GeoPark Colombia SAS; entering into certain related party transactions; and disposing of any material assets other than those provided for in an approved budget and work program. The LGI Colombia Agreements also provide that: (i) if either we or LGI decide to sell our respective shares in GeoPark Colombia SAS, the transferring shareholder must make an offer to sell those shares to the other shareholder before selling those shares to a third party; and (ii) any sale to a third party is subject to tag-along and drag-along rights, and the non-transferring shareholder has the right to object to a sale to the third-party if it considers such third-party to be not of a good reputation or one of our direct competitors. We and LGI also agreed to vote our common shares or otherwise cause GeoPark Colombia to declare dividends only after allowing for retentions for approved work programs and budgets, capital adequacy and tied surplus requirements of GeoPark Colombia, working capital requirements, banking covenants associated with any loan entered into by GeoPark Colombia or our other Colombian subsidiaries and operational requirements.

In addition, our agreement with LGI in Colombia allows us to earn back up to 12% of our equity participation in GeoPark Colombia, following certain recovery factors of LGI `s initial investments as follows: (i) if the recovery factor is between one and two times, our incremental equity share is 4%; if the recovery factor is between two to three, three to four, four to five, and above five, our incremental equity increases by an additional 2% each time, for up to a 12%, so that LGI participation could be reduced from current 20% to 8%. Recovery factor is measured considering realized dividends or other distributions over the original investments.

See "Item 4. Information on the Company—B. Business Overview—Significant Agreements—Agreements with LGI—LGI Colombia Agreements."

IFC Subscription and Shareholders' Agreement

On February 7, 2006, in order to finance the exploration, development and exploitation of our blocks in Chile and Argentina and the acquisition of additional exploration, development and exploitation blocks in Latin America, we, IFC and Gerald E. O'Shaughnessy and James F. Park, as Lead Investors, entered into an agreement (the "IFC Subscription and Shareholders' Agreement"), pursuant to which IFC agreed to subscribe and pay for 2,507,161 of our common shares, representing approximately 10.5% of our then-outstanding common shares, at an aggregate subscription price of US$10.0 million (or approximately US$3.99 per common share).

We agreed, for so long as IFC is a shareholder in the company, among other things, to: ensure that our operations are in compliance with certain environmental and social guidelines; appoint and maintain a technically qualified individual to be responsible for the environmental and social management of our activities; maintain certain forms of insurance coverage, including coverage for public liability and director's and officer's liability reasonably acceptable to IFC, and in respect of certain of our operations; not undertake certain prohibited activities; and ensure that no prohibited payments are made by us or on our or the Lead Investors' behalf, in respect of our operations.

We also agreed to provide to IFC, within 30 days of the end of the first half of the year, copies of our unaudited consolidated financial statements for the period (prepared under IFRS), a report on our capital expenditures for the period, a comprehensive report on the progress of the exploration, development and exploitation of our blocks in Latin America and a statement of all related party transactions during the period, with a certification by a company officer that these were on an arm's-length basis; within 90 days of the end of our fiscal year, copies of our audited consolidated financial statements for the year (prepared under IFRS), a management letter from our auditors in respect of our financial control procedures, accounting and management information systems and any litigation, an annual monitoring report confirming compliance with national or local requirements and the environmental and social requirements mandated by the agreement, a report indicating any payments in the year to any governmental authority in connection with the documents governing our Chilean and Argentine blocks and certificates of insurance, with a certificate of our insurer confirming that effectiveness of our policies and payment of all applicable premiums; within 45 days before each fiscal year begins, a proposed annual business plan and budget for the upcoming year; within 3 days after its occurrence, notification of any incident that had or may reasonably be expected to have an adverse effect on the environment, health or safety; copies of notices, reports or other communications between us and our board of directors or shareholders; and, within five days of receipt thereof, copies of any reports, correspondence, documentation or notices from any third-party, governmental authority or state-owned company that could reasonably be expected to materially impact our operations. Mr. O'Shaughnessy and Mr. Park have also agreed to procure that shareholders holding 51% of our common shares cause us to comply with the covenants above.

Executive Directors' Service Agreements

We have entered into service contracts with certain of our executive directors. See "Item 6. Directors, Senior Management and Employees—B. Compensation—Executive compensation—Director Contracts."

For further information relating to our related party transactions and balances outstanding as of December 31, 2017, 2016 and 2015, please see Note 33 to our Consolidated Financial Statements.

C. Interests of Experts and Counsel

Not applicable.

ITEM 8. FINANCIAL INFORMATION

A. Consolidated statements and other financial information

Financial statements

See "Item 18. Financial Statements," which contains our audited financial statements prepared in accordance with IFRS.

Legal proceedings

From time to time, we may be subject to various lawsuits, claims and proceedings that arise in the normal course of business, including employment, commercial, environmental, safety and health matters. For example, from time to time, we receive notice of environmental, health and safety violations. It is not presently possible to determine whether any such matters will have a material adverse effect on our consolidated financial position and results of operations.

In Brazil, GeoPark Brasil is a party to a class action filed by the Federal Prosecutor's Office regarding a concession agreement of exploratory Block PN-T-597, which the ANP initially awarded GeoPark Brasil in the 12th oil and gas bidding round held in November 2013. The Brazilian Federal Court issued an injunction against the ANP and GeoPark Brasil in December 2013 that prohibited GeoPark Brasil's execution of the concession agreement until the ANP conducted studies on whether drilling for unconventional resources would contaminate the dams and aquifers in the region. On July 17, 2015, GeoPark Brasil, at the instruction of the ANP, signed the concession agreement, which included a clause prohibiting GeoPark Brasil from conducting unconventional exploration activity in the area. Despite the clause containing the prohibition, the judge in the case concluded that the concession agreement should not be executed. Thus, GeoPark Brasil requested that the ANP comply with the decision and annul the concession agreement, which the ANP´s Board did on October 9, 2015. The annulment reverted the status of all parties to the status quo ante, which maintains GeoPark Brasil's right to the block.

Dividends and dividend policy

Holders of common shares will be entitled to receive dividends, if any, paid on the common shares.

We have never declared or paid any cash dividends on our common shares. We intend to retain all of our future earnings, if any, generated by our operations for the development and growth of our business. Accordingly, we do not expect to pay cash dividends on our common shares in the foreseeable future. Because we are a holding company with no direct operations, we will only be able to pay dividends from our available cash on hand and any funds we receive from our subsidiaries. The terms of our indebtedness may restrict us from paying dividends. Mainly resulting from the impact of the decline in oil prices, we have recorded accumulated losses amounting to US$283.9 million as of December 31, 2017, which further limits our ability to pay dividends in the foreseeable future.

Under the Bermuda Companies Act, we may not declare or pay a dividend if there are reasonable grounds for believing that we are, or would after the payment be, unable to pay our liabilities as they become due or that the realizable value of our assets would thereafter be less than our liabilities. We do not presently have any reasonable grounds for believing that, if we were to declare or pay a dividend on our common shares outstanding, we would thereafter be unable to pay our liabilities as they became due or that the realizable value of our assets would thereafter be less than our liabilities. Additionally, any decision to pay dividends in the future, and the amount of any distributions, is at the discretion of our board of directors and our shareholders, and will depend on many factors, such as our results of operations, financial condition, cash requirements, prospects and other factors. See "Item 3. Key Information—D. Risk factors—Risks related to our common shares—We have never declared or paid, and do not intend to pay in the foreseeable future, cash dividends on our common shares, and, consequently, your only opportunity to achieve a return on your investment is if the price of our stock appreciates" and "—We are a holding company dependent upon dividends from our subsidiaries, which may be limited by law and by contract from making distributions to us, which would affect our financial condition, including the ability to pay dividends on the common shares," as well as "Item 10. Additional Information—B. Memorandum of association and bye-laws."

B. Significant changes

A discussion of the significant changes in our business can be found under "Item 4. Information on the Company—B. Business Overview."

ITEM 9. THE OFFER AND LISTING

A. Offering and listing details
Not applicable.

B. Plan of distribution
Not applicable.

C. Markets
On February 6, 2014 we completed our initial public offering and listed our common shares on the NYSE.

Our common shares have been listed on the NYSE under the symbol "GPRK" since February 7, 2014. They were previously listed on the AIM under the symbol "GPK" until February 19, 2014, and, from 2009 to 2015 had been admitted to trade on the Santiago Offshore Stock Exchange (*Bolsa Offshore de la Bolsa de Comercio de Santiago*).

The table below presents, for the periods indicated, the annual, quarterly and monthly high and low closing prices (in US$) of our common shares on the NYSE.

	Common shares		
	High	Low	Average daily trading volume
	(US$ per share)		(in shares)
Annual price history			
2014 (from February 7 through December 31, 2014)	11.00	4.92	47,795
2015	5.59	2.70	23,838
2016	5.06	2.25	103,283
2017	10.05	4.50	142,158
2018 (through April 6, 2018)	12.58	9.24	162,292
Quarterly price history			
1st Quarter 2017	7.18	4.50	149,187
2nd Quarter 2017	8.89	6.55	202,151
3rd Quarter 2017	9.52	7.54	115,768
4th Quarter 2017	10.05	8.05	101,643
1st Quarter 2018	12.40	9.24	153,916
2nd Quarter 2018 (through April 6, 2018)	12.58	12.18	264,481
Monthly price history			
November 2017	9.83	8.48	142,290
December 2017	10.05	8.60	72,795
January 2018	10.88	9.60	125,886
February 2018	10.36	9.24	108,468
March 2018	12.40	9.35	223,067
April 2018 (through April 6, 2018)	12.58	12.18	264,481

Source: NYSE Connect

D. Selling shareholders
Not applicable.

E. Dilution
Not applicable.

F. Expenses of the issue
Not applicable.

ITEM 10. ADDITIONAL INFORMATION

A. Share capital
Not applicable.

B. Memorandum of association and bye-laws
The following description of our memorandum of association and bye-laws does not purport to be complete and is subject to, and qualified by reference to, all of the provisions of our memorandum of association and bye-laws.

General

We are an exempted company with limited liability incorporated under the laws of Bermuda with registration number 33273 from the Registrar of Companies. The rights of our shareholders will be governed by Bermuda law and by our memorandum of association and bye-laws. Bermuda company law differs in some material respects from the laws generally applicable to Delaware corporations. Below is a summary of some of those material differences.

Because the following statements are summaries, they do not discuss all aspects of Bermuda law that may be relevant to us and to our shareholders.

Share capital and bye-laws

Our share capital consists of common shares only. Our authorized share capital consists of 5,171,949,000 common shares of par value US$0.001 per share. As of the date of this annual report, there are 60,606,787 common shares outstanding. All of our issued and outstanding common shares are fully paid and non-assessable. We also have an employee incentive program, pursuant to which we have granted share awards to our senior management and certain key employees. See "Item 6. Directors, Senior Management and Employees."

According to our bye-laws, if our share capital is divided into different classes of shares, the rights attached to any class (unless otherwise provided by the terms of issue of the shares of that class) may, whether or not the Company is being wound-up, be varied with the consent in writing of the holders of at least two-thirds of the issued shares of that class or with the sanction of a resolution passed by a majority of the votes cast at a separate general meeting of the holders of the shares of the class at which meeting the necessary quorum shall be two persons at least, in person or by proxy, holding or representing one-third of the issued shares of the class. The rights conferred upon the holders of the shares of any class issued with preferred or other rights shall not, unless otherwise expressly provided by the terms of issue of the shares of that class, be deemed to be varied by the creation or issue of further shares ranking pari passu therewith.

Our bye-laws give our board of directors the power to issue any unissued shares of the company on such terms and conditions as it may determine, subject to the terms of the bye-laws and any resolution of the shareholders to the contrary.

Common shares

Holders of our common shares are entitled to one vote per share on all matters submitted to a vote of holders of common shares. Subject to preferences that may be applicable to any issued and outstanding preference shares, holders of common shares are entitled to receive such dividends, if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. Holders of common shares have no redemption, sinking fund, conversion, exchange or other subscription rights. In the event of our liquidation, the holders of common shares are entitled to share equally and ratably in our assets, if any, remaining after the payment of all of our debts and liabilities, subject to any liquidation preference on any outstanding preference shares.

Board composition

Our bye-laws provide that our board of directors will determine the maximum size of the board, provided that it shall be not be composed of fewer than three directors. The maximum number of directors currently allowed is nine directors and our board of directors currently consists of seven directors.

Election and removal of directors

Our bye-laws provide that our directors shall hold office for such term as the shareholders shall determine or, in the absence of such determination, until the next annual general meeting or until their successors are elected or appointed or their office is otherwise vacated. Directors whose term has expired may offer themselves for re-election at each election of the directors.

Under our bye-laws, a director may be removed by a resolution adopted by 65% or more of the votes cast by shareholders who (being entitled to do so) vote in person or by proxy at any general meeting of the shareholders in accordance with the provisions of our bye-laws. Notice convened for the purpose of removing the director, containing a statement of the intention to do so, must be served on such director not less than 14 days before the meeting.

Any vacancy created by the removal of a director at a special general meeting may be filled at that meeting by the election of another director in his or her place or, in the absence of any such election, by the board of directors. Any other vacancy, including a newly created directorship, may be filled by our board of directors.

Proceedings of board of directors

Our bye-laws provide that our business shall be managed by or under the direction of our board of directors. Our board of directors may act by the affirmative vote of a majority of the directors present at a meeting at which a quorum is present. The quorum necessary for the transaction of business at meetings of the board of directors shall be the presence of a majority of the board of directors from time to time. Our bye-laws also provide that resolutions unanimously signed by all directors are valid as if they had been passed at a meeting of the board duly called and constituted.

Duties of directors

Under Bermuda common law, members of a board of directors owe a fiduciary duty to the Company to act in good faith in their dealings with or on behalf of the company, and to exercise their powers and fulfill the duties of their office honestly. This duty has the following essential elements: (1) a duty to act in good faith in the best interests of the company; (2) a duty not to make a personal profit from opportunities that arise from the office of director; (3) a duty to avoid conflicts of interest; and (4) a duty to exercise powers for the purpose for which such powers were intended. The Bermuda Companies

Act also imposes a duty on directors of a Bermuda company, to act honestly and in good faith, with a view to the best interests of the company, and to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. In addition, the Bermuda Companies Act imposes various duties on directors with respect to certain matters of management and administration of the company.

The Bermuda Companies Act provides that in any proceedings for negligence, default, breach of duty or breach of trust against any director, if it appears to a court that such officer is or may be liable in respect of the negligence, default, breach of duty or breach of trust, but that he has acted honestly and reasonably, and that, having regard to all the circumstances of the case, including those connected with his appointment, he ought fairly to be excused for the negligence, default, breach of duty or breach of trust, that court may relieve him, either wholly or partly, from any liability on such terms as the court may think fit. This provision has been interpreted to apply only to actions brought by or on behalf of the company against the directors.

By comparison, under Delaware law, the business and affairs of a corporation are managed by or under the direction of its board of directors. In exercising their powers, directors are charged with a duty of care and a duty of loyalty. The duty of care requires that directors act in an informed and deliberate manner and to inform themselves, prior to making a business decision, of all relevant material information reasonably available to them. The duty of care also requires that directors exercise care in overseeing the conduct of corporate employees. The duty of loyalty is the duty to act in good faith, not out of self-interest, and in a manner which the director reasonably believes to be in the best interests of the shareholders. A party challenging the propriety of a decision of a board of directors bears the burden of rebutting the presumptions afforded to directors by the "business judgment rule." If the presumption is not rebutted, the business judgment rule attaches to protect the directors and their decisions. Where, however, the presumption is rebutted, the directors bear the burden of demonstrating the fairness of the relevant transaction. Notwithstanding the foregoing, Delaware courts subject directors' conduct to enhanced scrutiny in respect of defensive actions taken in response to a threat to corporate control and approval of a transaction resulting in a sale of control of the corporation.

Interested directors

Pursuant to our bye-laws, a director shall declare the nature of his interest in any contract or arrangement with the company as required by the Bermuda Companies Act. A director so interested shall not, except in particular circumstances set out in our bye-laws, be entitled to vote or be counted in the quorum at a meeting in relation to any resolution in which he has an interest, which is to his knowledge, a material interest (otherwise than by virtue of his interest in shares or debentures or other securities of or otherwise in or through the company). A director will be liable to us for any secret profit realized from the transaction. In contrast, under Delaware law, such a contract or arrangement is voidable unless it is approved by a majority of disinterested directors or by a vote of shareholders, in each case if the material facts as to the interested director's relationship or interests are disclosed or are known to the disinterested directors or shareholders, or such contract or arrangement is fair to the corporation as of the time it is approved or ratified. Additionally, such interested director could be held liable for a transaction in which such director derived an improper personal benefit.

Indemnification of directors and officers

Bermuda law provides generally that a Bermuda company may indemnify its directors and officers against any loss arising from or liability which by virtue of any rule of law would otherwise be imposed on them in respect of any negligence, default, breach of duty or breach of trust except in cases where such liability arises from fraud or dishonesty of which such director or officer may be guilty in relation to the company.

Our bye-laws provide that we shall indemnify our officers and directors in respect of their actions and omissions, except in respect of their fraud or dishonesty, or to recover any gain, personal profit or advantage to which such director is not legally entitled, and (by incorporation of the provisions of the Bermuda Companies Act) that we may advance monies to our officers and directors for costs, charges and expenses incurred by our officers and directors in defending any civil or criminal proceeding against them on the condition that the officers and directors repay the monies if any allegation of fraud or dishonesty is proved against them provided, however, that, if the Bermuda Companies Act requires, an advancement of expenses shall be made only upon delivery to the Company of an undertaking, by or on behalf of such indemnitee, to repay all amounts so advanced if it shall ultimately be determined by final judicial decision from which there is no further right to appeal that such indemnitee is not entitled to be indemnified for such expenses under this Bye-law or otherwise. Our bye-laws provide that the company and the shareholders waive all claims or rights of action that they might have, individually or in right of the company, against any of the company's directors or officers for any act or failure to act in the performance of such director's or officers' duties, except with respect to any fraud or dishonesty, or to recover any gain, personal profit or advantage to which such director is not legally entitled.

Meetings of shareholders

Under Bermuda law, a company is required to convene the annual general meeting of shareholders each calendar year, unless the shareholders in a general meeting, elect to dispense with the holding of annual general meetings. Under Bermuda law and our bye-laws, a special general meeting of shareholders may be called by the board of directors and may be called upon the requisition of shareholders holding not less than 10% of the paid-up capital of the company carrying the right to vote at general meetings of shareholders.

Our bye-laws provide that, at any general meeting of the shareholders, the presence in person or by proxy of two or more shareholders representing in excess of 50% of the total issued voting shares of the company shall constitute a quorum for the transaction of business unless the company only has one shareholder, in which case such shareholder shall constitute a quorum. Unless otherwise required by law or by our bye-laws, shareholder action requires a resolution adopted by a majority of votes cast by shareholders at a general meeting at which a quorum is present.

Shareholder proposals

Under Bermuda law, shareholders holding at least 5% of the total voting rights of all the shareholders having at the date of the requisition a right to vote at the meeting to which the requisition relates or any group composed of at least 100 or more shareholders may require a proposal to be submitted to an annual general meeting of shareholders. Under our bye-laws, any shareholders wishing to nominate a person for election as a director or propose business to be transacted at a meeting of shareholders must provide (among other things) advance notice, as set out in our bye-laws. Shareholders may only propose a person for election as a director at an annual general meeting.

Shareholder action by written consent

Our bye-laws provide that, except for the removal of auditors and directors, any actions which shareholders may take at a general meeting of shareholders may be taken by the shareholders through the unanimous written consent of the shareholders who would be entitled to vote on the matter at the general meeting.

Amendment of memorandum of association and bye-laws

Our memorandum of association and bye-laws may be amended with the approval of a majority of our board of directors and by a resolution by a majority of the votes cast by shareholders who (being entitled to do so) vote in person or by proxy at any general meeting of the shareholders in accordance with the provisions of the bye-laws.

Business combinations

A Bermuda company may engage in a business combination pursuant to a tender offer, amalgamation, merger or sale of assets. The amalgamation or merger of a Bermuda company with another company generally requires the amalgamation or merger agreement to be approved by the company's board of directors and by its shareholders. Shareholder approval is not required where (a) a holding company and one or more of its wholly-owned subsidiary companies amalgamate or merge or (b) two or more wholly-owned subsidiary companies of the same holding company amalgamate or merge. Under the Bermuda Companies Act (save for such "short-form amalgamations"), unless a company's bye-laws provide otherwise, the approval of 75% of the shareholders voting at a meeting is required to pass a resolution to approve the amalgamation or merger agreement, and the quorum for such meeting must be two persons holding or representing more than one-third of the issued shares of the company. Our bye-laws provide that an amalgamation or merger will require the approval of our board of directors and of our shareholders by a resolution adopted by 65% or more of the votes cast by shareholders who (being entitled to do so) vote in person or by proxy at any general meeting of the shareholders in accordance with the provisions of the bye-laws. Under Bermuda law, in the event of an amalgamation or merger of a Bermuda company with another company or corporation, a shareholder who did not vote in favor of the amalgamation or merger and who is not satisfied that fair value has been offered for such shareholder's shares may, within one month of the notice of the shareholders meeting, apply to the Supreme Court of Bermuda to appraise the value of those shares.

Under the Bermuda Companies Act, we are not required to seek the approval of our shareholders for the sale of all or substantially all of our assets. However, Bermuda courts will view decisions of the English courts as highly persuasive and English authorities suggest that such sales do require shareholder approval. Our bye-laws provide that the directors shall manage the business of the Company and may exercise all such powers as are not, by the Bermuda Companies Act or by these Bye-laws, required to be exercised by the Company in general meeting and may pay all expenses incurred in promoting and incorporating the company and may exercise all the powers of the Company including, but not by way of limitation, the power to borrow money and to mortgage or charge all or any part of the undertaking property and assets (present and future) and uncalled capital of the Company and to issue debentures and other securities, whether outright or as collateral security for any debt, liability or obligation of the Company or any other persons.

Under Bermuda law, where an offer is made for shares of a company and, within four months of the offer, the holders of not less than 90% of the shares not owned by the offeror, its subsidiaries or their nominees accept such offer, the offeror may by notice require the non-tendering shareholders to transfer their shares on the terms of the offer. Dissenting shareholders do not have express appraisal rights but are entitled to seek relief (within one month of the compulsory acquisition notice) from the court, which has power to make such orders as it thinks fit. Additionally, where one or more parties hold not less than 95% of the shares of a company, such parties may, pursuant to a notice given to the remaining shareholders, acquire the shares of such remaining shareholders. Dissenting shareholders have a right to apply to the court for appraisal of the value of their shares within one month of the compulsory acquisition notice. If a dissenting shareholder is successful in obtaining a higher valuation, that valuation must be paid to all shareholders being squeezed out or the purchaser may cancel the purchase notice sent.

Dividends and repurchase of shares

Pursuant to our bye-laws, our board of directors has the authority to declare dividends and authorize the repurchase of shares subject to applicable law. Under Bermuda law, a company may not declare or pay a dividend if there are reasonable grounds for believing that the company is, or would after the payment be, unable to pay its liabilities as they become due or the realizable value of its assets would thereby be less than its liabilities. Under Bermuda law, a company cannot purchase its own shares if there are reasonable grounds for believing that the company is, or after the repurchase would be, unable to pay its liabilities as they become due.

Shareholder suits

Class actions and derivative actions are generally not available to shareholders under Bermuda law. The Bermuda courts, however, would ordinarily be expected to permit a shareholder to commence an action in the name of a company to remedy a wrong to the company where the act complained of is alleged to be beyond the corporate power of the company or illegal, or would result in the violation of the company's memorandum of association or bye-laws. Furthermore, consideration would be given by a Bermuda court to acts that are alleged to constitute a fraud against the minority shareholders or where an act requires the approval of a greater percentage of the company's shareholders than that which actually approved it.

When the affairs of a company are being conducted in a manner which is oppressive or prejudicial to the interests of some part of the shareholders, one or more shareholders may apply under the Bermuda Companies Act for an order of the Supreme Court of Bermuda, which may make such order as it sees fit, including an order regulating the conduct of the company's affairs in the future or ordering the purchase of the shares of any shareholders by other shareholders or by the company.

Our bye-laws contain a provision through which we and our shareholders waive any claim or right of action that we or they have, both individually and on our behalf, against any director or officer in relation to any action or failure to take action by such director or officer, including the breach of any fiduciary duty, except in respect of any fraud or dishonesty of such director or officer.

Comparison of Bermuda law to Delaware corporate law

Bermuda law differs from the laws in effect in the United States and might afford less protection to shareholders.

Our shareholders could have more difficulty protecting their interests than would shareholders of a corporation incorporated in a jurisdiction of the United States. As a Bermuda company, we are governed by our memorandum of association and bye-laws and Bermuda company law. The provisions of the Bermuda Companies Act, which applies to us, differs in some material respects from laws generally applicable to U.S. corporations and shareholders, including the provisions relating to interested directors, mergers and acquisitions, takeovers, shareholder lawsuits and indemnification of directors. Set forth below is a summary of these provisions, as well as modifications adopted pursuant to our bye-laws, which differ in certain respects from provisions of Delaware corporate law. Our shareholders approved the adoption of new bye-laws which came into effect on February 19, 2014, being the date on which the company cancelled admission of its common shares on AIM. Because the following statements are summaries, they do not discuss all aspects of Bermuda law that may be relevant to us and our shareholders.

Interested Directors . Under our bye-laws and the Bermuda Companies Act, a director shall declare the nature of his interest in any contract or arrangement with the company. Our bye-laws further provide that a director so interested shall not, except in particular circumstances, be entitled to vote or be counted in the quorum at a meeting in relation to any resolution in which he has an interest, which is to his knowledge, a material interest (otherwise than by virtue of his interest in shares or debentures or other securities of or otherwise in or through the company). A director will be liable to us for any secret profit realized from the transaction. See "Item 10—B. Memorandum of association and bye-laws—Interested Directors."

Amalgamations, Mergers and Similar Arrangements . Pursuant to the Bermuda Companies Act, the amalgamation or merger of a Bermuda company with another company or corporation requires the amalgamation or merger agreement to be approved by the company's board of directors and, under certain circumstances, by its shareholders. Under our bye-laws, an amalgamation or merger will require the approval of our board of directors and our shareholders by Special Resolution, which is a resolution adopted by 65% of more of the votes cast by shareholders who (being entitled to do so) vote in person or by proxy at any general meeting of the shareholders in accordance with the provisions of the bye-laws and the quorum for any general meeting must be two or more persons, in person or by proxy, representing in excess of 50% of the total of our issued voting shares. Under Bermuda law, in the event of an amalgamation or merger of a Bermuda company with another company or corporation, a shareholder of the Bermuda company who did not vote in favor of the amalgamation or merger and who is not satisfied that he has been offered fair value for his shares may, within one month of notice of the shareholders meeting, apply to the Supreme Court of Bermuda to appraise the fair value of those shares.

Under Delaware law, with certain exceptions, a merger, consolidation or sale of all or substantially all the assets of a corporation must be approved by the board of directors and a majority of the issued and outstanding shares entitled to vote thereon. Under Delaware law, a shareholder of a corporation participating in certain major corporate transactions may, under certain circumstances, be entitled to appraisal rights pursuant to which such shareholder may receive cash in the amount of the fair value of the shares held by such shareholder (as determined by a court) in lieu of the consideration such shareholder would otherwise receive in the transaction.

Shareholders' Suit . Class actions and derivative actions are generally not available to shareholders under Bermuda law. The Bermuda courts, however, would ordinarily be expected to permit a shareholder to commence an action in the name of a company to remedy a wrong to the company where the act complained of is alleged to be beyond the corporate power of the company or illegal, or would result in the violation of the company's memorandum of association or bye-laws. When the affairs of a company are being conducted in a manner which is oppressive or prejudicial to the interests of some part of the shareholders, one or more shareholders may apply for an order of the Supreme Court of Bermuda regulating the conduct of the company's affairs in the future or an order to purchase the shares of any shareholders by other shareholders or by the company and, in the case of a purchase by the company, for the reduction accordingly of the company's capital, or otherwise. See "Item 10—B. Memorandum of association and bye-laws—Shareholder Suits."

Our bye-laws contain a provision by virtue of which we and our shareholders waive any claim or right of action that they have, both individually and on our behalf, against any director or officer in relation to any action or failure to take action by such director or officer, including the breach of any fiduciary duty, except in respect of any fraud or dishonesty of such director or officer. Class actions and derivative actions generally are available to shareholders under Delaware law for, among other things, breach of fiduciary duty, corporate waste and actions not taken in accordance with applicable law. In such actions, the court has discretion to permit the winning party to recover attorneys' fees incurred in connection with such action.

Indemnification of Directors . We may indemnify our directors and officers in their capacity as directors or officers for any loss arising or liability attaching to them by virtue of any rule of law in respect of any negligence, default, breach of duty or breach of trust of which a director or officer may be guilty in relation to the company other than in respect of his own fraud or dishonesty. See "Item 10—B. Memorandum of association and bye-laws—Enforcement of Judgments." Our bye-laws provide that we shall indemnify our officers and directors in respect of their acts and omissions, except in respect of their fraud or dishonesty, or to recover any gain, personal profit or advantage to which such Director is not legally entitled, and (by incorporation of the provisions of the Bermuda Companies Act) that we may advance money to our officers and directors for the costs, charges and expenses incurred by our officers and directors in defending any civil or criminal proceedings against them on condition that the directors and officers repay the money if any allegations of fraud or dishonesty is proved against them provided, however, that, if the Bermuda Companies Act requires, an advancement of expenses shall be made only upon delivery to the Company of an undertaking, by or on behalf of such indemnitee, to repay all amounts if it shall ultimately be determined by final decision that such indemnitee is not entitled to be indemnified for such expenses under our Bye-laws or otherwise. Under Delaware law, a corporation may indemnify a director or officer of the corporation against expenses (including attorneys' fees), judgments, fines and amounts paid in settlement actually and reasonably incurred in defense of an action, suit or proceeding by reason of such position if such director or officer acted in good faith and in a manner he or she reasonably believed to be in or not opposed to the best interests of the corporation and, with respect to any criminal action or proceeding, such director or officer had no reasonable cause to believe his or her conduct was unlawful. In addition, we have entered into customary indemnification agreements with our directors.

As a result of these differences, investors could have more difficulty protecting their interests than would shareholders of a corporation incorporated in the United States.

Tax matters . Under current Bermuda law, we are not subject to tax on income or capital gains. We have received from the Minister of Finance under The Exempted Undertaking Tax Protection Act 1966, as amended, an assurance that, in the event that Bermuda enacts legislation imposing tax computed on profits, income, any capital asset, gain or appreciation, or any tax in the nature of estate duty or inheritance, then the imposition of any such tax shall not be applicable to us or to any of our operations or shares, debentures or other obligations, until March 31, 2035. We could be subject to taxes in Bermuda after that date. This assurance is subject to the provision that it is not to be construed to prevent the application of any tax or duty to such persons as are ordinarily resident in Bermuda or to prevent the application of any tax payable in accordance with the provisions of the Land Tax Act 1967 or otherwise payable in relation to any property leased to us. We are incorporated in Bermuda as an exempted company and pay annual Bermuda government fees. In addition, all entities employing individuals in Bermuda are required to pay a payroll tax and there are other sundry taxes payable, directly or indirectly, to the Bermuda government. Neither we nor our Bermuda subsidiaries employ individuals in Bermuda as at the date of this annual report.

Access to books and records and dissemination of information

Members of the general public have a right to inspect the public documents of a company available at the office of the Registrar of Companies in Bermuda. These documents include the company's memorandum of association and any amendments thereto. The shareholders have the additional right to inspect the bye-laws of the company, minutes of general meetings of shareholders and the company's audited financial statements. The company's audited financial statements must be presented at the annual general meeting of shareholders, unless the board and all the shareholders agree to the waiving of the audited financials. The company's share register is open to inspection by shareholders and by members of the general public without charge. A company is required to maintain its share register in Bermuda but may, subject to the provisions of the Bermuda Companies Act, establish a branch register outside of Bermuda. Bermuda law does not, however, provide a general right for shareholders to inspect or obtain copies of any other corporate records.

Registrar or transfer agent

A register of holders of the common shares is maintained by Coson Corporate Services Limited in Bermuda, and a branch register is maintained in the United States by Computershare Trust Company, N.A., who serves as branch registrar and transfer agent.

Enforcement of Judgments

We are incorporated as an exempted company with limited liability under the laws of Bermuda, and substantially all of our assets are located in Colombia, Chile, Brazil, Peru and Argentina. In addition, most of our directors and executive officers reside outside the United States, and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors to effect service of process on those persons in the United States or to enforce in the United States judgments obtained in U.S. courts against us or those persons based on the civil liability provisions of the U.S. securities laws.

There is no treaty in force between the United States and Bermuda providing for the reciprocal recognition and enforcement of judgments in civil and commercial matters. As a result, whether a U.S. judgment would be enforceable in Bermuda against us or our directors and officers depends on whether the U.S. court that entered the judgment is recognized by the Bermuda court as having jurisdiction over us or our directors and officers, as determined by reference to Bermuda conflict of law rules and the judgment is not contrary to public policy in Bermuda, has not been obtained by fraud in proceedings contrary to natural justice and is not based on an error in Bermuda law. A judgment debt from a U.S. court that is final and for a sum certain based on U.S. federal securities laws will not be enforceable in Bermuda unless the judgment debtor had submitted to the jurisdiction of the U.S. court, and the issue of submission and jurisdiction is a matter of Bermuda (not U.S.) law.

An action brought pursuant to a public or penal law, the purpose of which is the enforcement of a sanction, power or right at the instance of the state in its sovereign capacity, may not be entertained by a Bermuda court. Certain remedies available under the laws of U.S. jurisdictions, including certain remedies under U.S. federal securities laws, may not be available under Bermuda law or enforceable in a Bermuda court, as they may be contrary to Bermuda public policy. Further, no claim may be brought in Bermuda against us or our directors and officers in the first instance for violations of U.S. federal securities laws because these laws have no extraterritorial jurisdiction under Bermuda law and do not have force of law in Bermuda. A Bermuda court may, however, impose civil liability on us or our directors and officers if the facts alleged in a complaint constitute or give rise to a cause of action under Bermuda law. However, section 281 of the Bermuda Companies Act allows a Bermuda court, in certain circumstances, to relieve officers and directors of Bermuda companies of liability for acts of negligence, breach of duty or trust or other defaults.

Section 98 of the Bermuda Companies Act provides generally that a Bermuda company may indemnify its directors, officers and auditors against any liability which by virtue of any rule of law would otherwise be imposed on them in respect of any negligence, default, breach of duty or breach of trust, except in cases where such liability arises from fraud or dishonesty of which such director, officer or auditor may be guilty in relation to the company.

Section 98 further provides that a Bermuda company may indemnify its directors, officers and auditors against any liability incurred by them in defending any proceedings, whether civil or criminal, in which judgment is awarded in their favor or in which they are acquitted or granted relief by the Supreme Court of Bermuda pursuant to Section 281 of the Bermuda Companies Act.

Our bye-laws contain provisions whereby we and our shareholders waive any claim or right of action that we have, both individually and on our behalf, against any director or officer in relation to any action or failure to take action by such director or officer, except in respect of any fraud or dishonesty of such director or officer. We may also indemnify our directors and officers in their capacity as directors and officers for any loss arising or liability attaching to them by virtue of any rule of law in respect of any negligence, default, breach of trust of which a director or officer may be guilty in relation to the company other than in respect of his own fraud or dishonesty. We have entered into customary indemnification agreements with our directors.

No treaty exists between the United States and Chile for the reciprocal recognition and enforcement of foreign judgments. Chilean courts, however, have enforced valid and conclusive judgments for the payment of money rendered by competent U.S. courts by virtue of the legal principles of reciprocity and comity, subject to review in Chile of the U.S. judgment in order to ascertain whether certain basic principles of due process and public policy have been respected, without retrial or review of the merits of the subject matter. If a U.S. court grants a final judgment, enforceability of this judgment in Chile will be subject to obtaining the relevant exequatur (i.e., recognition and enforcement of the foreign judgment) according to Chilean civil procedure law in effect at that time, and depending on certain factors (the satisfaction or non-satisfaction of which would be determined by the Supreme Court of Chile). Currently, the most important of such factors are: the existence of reciprocity (if it can be proved that there is no reciprocity in the recognition and enforcement of the foreign judgment between the United States and Chile, that judgment would not be enforced in Chile); the absence of any conflict between the foreign judgment and Chilean laws (excluding for this purpose the laws of civil procedure) and Chilean public policy; the absence of a conflicting judgment by a Chilean court relating to the same parties and arising from the same facts and circumstances; the Chilean court's determination that the U.S. courts had jurisdiction, that process was appropriately served on the defendant and that the defendant was afforded a real opportunity to appear before the court and defend its case; and the judgment being final under the laws of the country in which it was rendered. Nonetheless, we have been advised by our Chilean counsel that there is doubt as to the enforceability in original actions in Chilean courts of liabilities predicated solely upon U.S. federal or state securities laws.

C. Material contracts

See "Item 4. Information on the Company—B. Business Overview—Significant Agreements."

D. Exchange controls
Not applicable.

E. Taxation
The following summary contains a description of certain Bermudian, U.S. federal income, and Chilean tax consequences of the acquisition, ownership and disposition of our common shares. The summary is based upon the tax laws of Bermuda, the United States, and Chile, and regulations thereunder as of the date hereof, which are subject to change.

Bermuda tax consideration
At the date of this annual report, there is no Bermuda income or profits tax, withholding tax, capital gains tax, capital transfer tax, estate duty or inheritance tax payable by us or by our shareholders in respect of our common shares. We have obtained an assurance from the Minister of Finance of Bermuda under the Exempted Undertakings Tax Protection Act 1966 that, in the event that any legislation is enacted in Bermuda imposing any tax computed on profits or income, or computed on any capital asset, gain or appreciation or any tax in the nature of estate duty or inheritance tax, such tax shall not, until March 31, 2035, be applicable to us or to any of our operations or to our common shares, debentures or other obligations except insofar as such tax applies to persons ordinarily resident in Bermuda or is payable by us in respect of real property owned or leased by us in Bermuda. We pay annual Bermuda government fees.

Material U.S. federal income tax considerations
The following is a description of the material U.S. federal income tax consequences to U.S. Holders (as defined below) of owning and disposing of our common shares. This discussion is not a comprehensive description of all tax considerations that may be relevant to a particular person's decision to hold our common shares. This discussion applies only to a U.S. Holder that holds our common shares as capital assets for tax purposes. In addition, it does not describe all of the tax consequences that may be relevant in light of the U.S. Holder's particular circumstances, including alternative minimum tax and Medicare contribution tax consequences and differing tax consequences applicable to a U.S. Holder subject to special rules, such as:

- certain financial institutions;
- a dealer or trader in securities who uses a mark-to-market method of tax accounting;
- a person holding common shares as part of a straddle, wash sale or conversion transaction or entering into a constructive sale with respect to the common shares;
- a person whose functional currency for U.S. federal income tax purposes is not the US$;
- a partnership or other entities classified as partnerships for U.S. federal income tax purposes;
- a tax-exempt entity, including an "individual retirement account" or "Roth IRA;"
- a person that owns or is deemed to own 10% or more of our voting stock;
- a person who acquired our shares pursuant to the exercise of an employee stock option or otherwise as compensation; or
- a person holding common shares in connection with a trade or business conducted outside of the United States.

If an entity that is classified as a partnership for U.S. federal income tax purposes holds common shares, the U.S. federal income tax treatment of a partner will generally depend on the status of the partner and the activities of the partnership. Partnerships holding common shares and partners in such partnerships should consult their tax advisers as to the particular U.S. federal income tax consequences of their investment in our common shares.

This discussion is based on the Internal Revenue Code of 1986, as amended (the "Code"), administrative pronouncements, judicial decisions, and final, temporary and proposed Treasury regulations, all as of the date hereof, any of which is subject to change, possibly with retroactive effect. U.S. Holders should consult their tax advisers concerning the U.S. federal, state, local and foreign tax consequences of owning and disposing of our common shares in their particular circumstances.

A "U.S. Holder" is a beneficial owner of our common shares for U.S. federal income tax purposes that is:

- a citizen or individual resident of the United States;
- a corporation, or other entity taxable as a corporation, created or organized in or under the laws of the United States, any state therein or the District of Columbia; or
- an estate or trust the income of which is subject to U.S. federal income taxation regardless of its source.

This discussion assumes that we are not, and will not become, a passive foreign investment company, as described below.

Taxation of distributions
Distributions paid on our common shares, other than certain pro rata distributions of common shares, will generally be treated as dividends to the extent paid out of our current or accumulated earnings and profits (as determined under U.S. federal income tax principles). Because we do not maintain calculations of our earnings and profits under U.S. federal income tax principles, it is expected that distributions will generally be reported to U.S. Holders as dividends. Subject to the passive foreign investment company rules described below, dividends paid by qualified foreign corporations to certain non-corporate U.S. Holders may be taxable at favorable rates. A foreign corporation is treated as a qualified foreign corporation with respect to dividends paid on stock that is readily tradable on a securities market in the United States, such as the NYSE where our common shares are traded. Non-corporate U.S. Holders should consult their tax advisers to determine whether the favorable rate will apply to dividends they receive and whether they are subject to any special rules that limit their ability to be taxed at this favorable rate.

A dividend generally will be included in a U.S. Holder's income when received, will be treated as foreign-source income to U.S. Holders and will not be eligible for the dividends-received deduction generally available to U.S. corporations under the Code with respect to dividends paid by domestic corporations.

Sale or other taxable disposition of common shares
Gain or loss realized on the sale or other taxable disposition of our common shares will be capital gain or loss, and will be long-term capital gain or loss if the U.S. Holder held our common shares for more than one year. Long-term capital gain of a non-corporate U.S. Holder is generally taxed at preferential rates. The deductibility of capital losses is subject to limitations. The amount of the gain or loss will equal the difference between the U.S. Holder's tax basis in the common shares disposed of and the amount realized on the disposition. If a Chilean tax is withheld on the sale or disposition of the common shares, a U.S. Holder's amount realized will include the gross amount of the proceeds of the sale or disposition before deduction of the Chilean tax. See "—Chilean tax on transfers of shares" for a description of when a disposition may be subject to taxation by Chile. This gain or loss will generally be U.S.-source gain or loss for foreign tax credit purposes. U.S. Holders should consult their tax advisers as to whether the Chilean tax on gains may be creditable against the U.S. Holder's U.S. federal income tax on foreign-source income from other sources.

Passive foreign investment company rules
We believe that we were not a "passive foreign investment company," or PFIC, for U.S. federal income tax purposes for 2017, and we do not expect to be a PFIC in the foreseeable future. However, because the composition of our income and assets will vary over time, there can be no assurance that we will not be a PFIC for any taxable year. The determination of whether we are a PFIC is made annually and is based upon the composition of our income and assets (including the income and assets of, among others, entities in which we hold at least a 25% interest), and the nature of our activities.

If we were a PFIC for any taxable year during which a U.S. Holder held our common shares, gain recognized by a U.S. Holder on a sale or other disposition (including certain pledges) of our common shares would generally be allocated ratably over the U.S. Holder's holding period for the common shares. The amounts allocated to the taxable year of the sale or other disposition and to any year before we became a PFIC would be taxed as ordinary income. The amount allocated to each other taxable year would be subject to tax at the highest rate in effect for individuals or corporations for that year, as appropriate, and an interest charge would be imposed on the tax on such amount. Further, to the extent that any distribution received by a U.S. Holder on its common shares exceeds 125% of the average of the annual distributions on the shares received during the preceding three years or the U.S. Holder's holding period, whichever is shorter, that distribution would be subject to taxation in the same manner as gain, as described immediately above. Certain elections may be available that would result in alternative treatments (such as mark-to-market treatment) of our common shares. U.S. Holders should consult their tax advisers to determine whether any of these elections would be available and, if so, what the consequences of the alternative treatments would be in their particular circumstances.

Furthermore, if we were a PFIC or, with respect to a particular U.S. Holder, were treated as a PFIC for the taxable year in which we paid a dividend or the prior taxable year, the preferential dividend rates discussed above with respect to dividends paid to certain non-corporate U.S. Holders would not apply.

Information reporting and backup withholding
Payments of dividends and sales proceeds that are made within the United States or through certain U.S.-related financial intermediaries generally are subject to information reporting, and may be subject to backup withholding, unless (1) the U.S. Holder is a corporation or other exempt recipient or (2) in the case of backup withholding, the U.S. Holder provides a correct taxpayer identification number and certifies that it is not subject to backup withholding. The amount of any backup withholding from a payment to a U.S. Holder will be allowed as a credit against the U.S. Holder's U.S. federal income tax liability and may entitle it to a refund, provided that the required information is timely furnished to the Internal Revenue Service.

Chilean tax on transfers of shares
In September 2012, Article 10 of the Chilean Income Tax Law Decree Law No. 824 of 1974, or the indirect transfer rules, were enacted, and impose taxes on the indirect transfer of shares, equity rights, interests or other rights in the equity, control or profits of a Chilean entity as well as transfers of other assets and property of permanent establishments or other businesses in Chile. The 2014 tax reform introduces a measure which obliges the company from which shares are transferred to pay taxes if the entity which undertakes the transfer of shares fails to do so.

The indirect transfer rules apply to sales of shares of an entity:
- If such entity is an offshore holding company located in a black-listed tax haven jurisdiction as determined by Chilean tax law, or a black-listed jurisdiction, (such as Bermuda) that holds Chilean Assets; and either a Chilean resident holds 5% or more of such entity, or such entity's rights to equity, control or profits, or 50% or more of such entity's rights to equity or profits are held by residents in black-listed jurisdictions; or
- the shares or rights transferred represent 10% or more of the offshore holding company (considering dispositions by related persons and over the preceding 12-month period) and the underlying Chilean Assets indirectly transferred, in the proportion indirectly owned by the seller, (a) are valued in an amount equal to or higher than UTA 210,000 (approximately US$200 million) (adjusted by the Chilean inflation unit of reference) or (b) represent 20% or more of the market value of the interest held by such seller in such offshore holding company.

As a result of these rules, a capital gain tax of 35% will be applied by the Chilean tax authorities to the sale of any of our common shares if either of the above alternative are met. This rate might be subject to change in the short term. See "Item 4. Information on the Company—B. Business overview—Industry and regulatory framework —Chile."

As of December 31, 2017, our Chilean Assets represented more than UTA 210,000 and represent more than 38% of our total assets.
The 35% rate is calculated pursuant to one of the following methods, as determined by the seller:

- the sale price of the shares minus the acquisition cost of such shares, multiplied by the percentage or proportion of the part of the underlying Chilean Assets' fair market value (which assets are deemed to be "indirectly transferred" by virtue of the sale of shares) to the fair market value of the shares of the seller; or
- the portion of the sales price of the shares equal to the proportion of the fair market value of the underlying Chilean Assets, minus the corresponding proportion in the tax cost of such Chilean Assets for the corresponding holding entity.

However, the seller may opt to be taxed as if the underlying Chilean Assets had been sold directly in which case a different set of tax rules may apply. The tax is payable by the seller of the shares; however, the buyer shall make a provisional withholding unless the seller declares and pays the tax within the month following the sale, payment, remittance or it is credited into its account or is put at its disposal. Also, if the seller fails to declare and pay this tax, and the buyer has not complied with its withholding obligations, the Chilean tax authority (Servicio de Impuestos Internos) may charge such tax directly to any of them. In addition, the Chilean tax authority may require us, the seller, the buyer, or its representative in Chile, to file an affidavit with the information necessary to assess this tax.

Based on information available to us, (i) no Chilean resident holds 5% or more of our rights to equity, control or profits; or (ii) residents in black-listed jurisdictions hold 50% or more of our rights to equity, control or profits. Therefore, we do not believe the indirect transfer rules will apply to transfers of our common shares, unless the shares or rights transferred represent 10% or more of the company and the other conditions described above are met (considering dispositions by related persons and over the preceding 12-month period).

However, there can be no assurance that, at any time in the future, a Chilean resident will not hold 5% or more of our rights to equity, control or profits or that residents in black-listed jurisdictions will not hold 50% or more of our rights to equity, control or profits. If this were to occur, all sales of our common shares would be subject to the indirect transfer tax referred to above.
Our expectations regarding the indirect transfer rules are based on our understandings, analysis and interpretation of these enacted indirect transfer rules, which are subject to additional interpretation and rule-making by the Chilean authorities. As such, there is uncertainty relating to the application by Chilean authorities of the indirect transfer rules on us.
See "Item 3. Key Information—D. Risk Factors—Risks related to our common shares—The transfer of our common shares may be subject to capital gains taxes pursuant to indirect transfer rules in Chile."

F. Dividends and paying agents
Not applicable.

G. Statement by experts
Not applicable.

H. Documents on display
We are subject to the informational requirements of the Exchange Act. Accordingly, we are required to file reports and other information with the SEC, including annual reports on Form 20-F and reports on Form 6-K. You may inspect and copy reports and other information filed with the SEC at the Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet website that contains reports and other information about issuers, like us, that file electronically with the SEC. The address of that website is www.sec.gov.

I. Subsidiary information
Not applicable.

ITEM 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to a variety of market risks, including commodity price risk, interest rate risk, currency risk and credit (counterparty and customer) risk.

The term "market risk" refers to the risk of loss arising from adverse changes in interest rates, oil and natural gas prices and foreign currency exchange rates. For further information on our market risks, please see Note 3 to our Consolidated Financial Statements.

ITEM 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

A. Debt securities
Not applicable.

B. Warrants and rights
Not applicable.

C. Other securities
Not applicable.

D. American Depositary Shares
Not applicable.

ITEM 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

A. Defaults
No matters to report.

B. Arrears and delinquencies
No matters to report.

ITEM 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

Not applicable.

ITEM 15. CONTROLS AND PROCEDURES

A. Disclosure Controls and Procedures
As of December 31, 2017, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act). There are inherent limitations to the effectiveness of any disclosure controls and procedures system, including the possibility of human error and circumventing or overriding them. Even if effective, disclosure controls and procedures can provide only reasonable assurance of achieving their control objectives.

Based on such evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to provide reasonable assurance that the information we are required to disclose in the reports we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and (2) accumulated and communicated to our management to allow timely decisions regarding required disclosures.

B. Management's Annual Report on Internal Control over Financial Reporting
Our management is responsible for establishing and maintaining an adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act.

Our internal control over financial reporting is a process designed by, or under the supervision of, our principal executive and principal financial officers, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes, in accordance with generally accepted accounting principles. These include those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements, in accordance with generally accepted accounting principles, and that receipts and expenditures are being made only in accordance with authorization of our management and directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, effective control over financial reporting cannot, and does not, provide absolute assurance of achieving our control objectives. Also, projections of, and any evaluation of effectiveness of the internal controls in future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our Chief Executive Officer, our Chief Financial Officer, and our Director of Legal and Governance, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework of the Committee of Sponsoring Organizations of the Treadway Commission (2013).

Based on this assessment, management believes that, as of December 31, 2017, its internal control over financial reporting was effective based on those criteria.

C. Attestation Report of the Registered Public Accounting Firm
Not applicable.

D. Changes in Internal Control over Financial Reporting
There have been no changes in our internal control over financial reporting during the period covered by this annual report on Form 20-F that have materially affected or reasonably likely to materially affect our internal control over financial reporting.

ITEM 16. RESERVED

ITEM 16A. Audit committee financial expert

We have determined that Mr. Juan Cristóbal Pavez and Mr. Robert Bedingfield are independent, as such term is defined under SEC rules applicable to foreign private issuers. In addition, Mr. Robert Bedingfield and Mr. Juan Cristobal Pavez are regarded as audit committee financial experts.

ITEM 16B. Code of Conduct

We have adopted a code of conduct applicable to the board of directors and all employees. Since its effective date on September 24, 2012, we have not waived compliance with or amended the code of conduct.

ITEM 16C. Principal Accountant Fees and Services

Amounts billed by PwC for audit and other services were as follows:

	2017	2016
	(in millions of US$)	
Audit fees	0.73	0.49
Audit related fees	0.14	—
Tax services fees	0.21	0.13
Other fees paid	0.03	—
Total	**1.11**	**0.62**

Audit Fees
Audit fees are fees billed for professional services rendered by the principal accountant for the audit of the registrant's annual financial statements or services that are normally provided by the accountant in connection with statutory and regulatory filings or engagements for those fiscal years. It includes the audit of our Consolidated Financial Statements and other services that generally only the independent accountant reasonably can provide, such as comfort letters, statutory audits, consents and assistance with and review of documents filed with the SEC.

Audit-Related Fees
Audit-related fees are fees billed for assurance and related services that are reasonably related to the performance of the audit or review of our Consolidated Financial Statements and not reported under the previous category. These services would include, among others: accounting consultations and audits in connection with acquisitions, internal control reviews, attest services that are not required by statue or regulation and consultation concerning financial accounting and reporting standards.

Tax Fees
Tax fees are fees billed for professional services for tax compliance, tax advice and tax planning.

Pre-Approval Policies and Procedures
Following the listing of our common shares on the NYSE, the Audit Committee proposes the appointment of the independent auditor to the Board to be put to shareholders for approval at the Annual General meeting. The committee oversees the auditor selection process for new auditors and ensures key partners in the appointed firm are rotated in accordance with best practices. Also, following our NYSE listing, the Audit Committee is required to pre-approve the audit and non-audit fees and services performed by the Company's auditors in order to be sure that the provision of such services does not impair the audit firm's independence.
All of the audit fees, audit-related fees and tax fees described in this item 16C have been approved by the Audit Committee.

ITEM 16D. Exemptions from the listing standards for audit committees

None.

ITEM 16E. Purchases of equity securities by the issuer and affiliated purchasers

During 2017, no purchases of our common shares were made by or on behalf of us or by any affiliated purchaser.

ITEM 16F. Change in registrant's certifying accountant

Not applicable.

ITEM 16G. Corporate governance

Our common shares are listed on the NYSE. We are therefore required to comply with certain of the NYSE's corporate governance listing standards (the "NYSE Standards"). As a foreign private issuer, we may follow our home country's corporate governance practices in lieu of most of the NYSE Standards. Our corporate governance practices differ in certain significant respects from those that U.S. companies must adopt in order to maintain NYSE listing and, in accordance with Section 303A.11 of the NYSE Listed Company Manual, a brief, general summary of those differences is provided as follows.

Director independence
The NYSE Standards require a majority of the membership of NYSE-listed company boards to be composed of independent directors. Neither Bermuda law, the law of our country of incorporation, nor our memorandum of association or bye-laws require a majority of our board to consist of independent directors.

Non-management directors' executive sessions
The NYSE Standards require non-management directors of NYSE-listed companies to meet at regularly scheduled executive sessions without management. Our memorandum of association and bye-laws do not require our non-management directors to hold such meetings.

Committee member composition
The NYSE Standards require domestic NYSE-listed domestic companies to have a nominating/corporate governance committee and a compensation committee that are composed entirely of independent directors. Bermuda law, the law of our country of incorporation, does not impose similar requirements.

Independence of the compensation committee and its advisers
On January 11, 2013, the SEC approved NYSE listing standards that require

that the board of directors of a domestic listed company consider two factors (in addition to the existing general independence tests) in the evaluation of the independence of compensation committee members: (i) the source of compensation of the director, including any consulting, advisory or other compensatory fees paid by the listed company, and (ii) whether the director has an affiliate relationship with the listed company, a subsidiary of the listed company or an affiliate of a subsidiary of the listed company. In addition, before selecting or receiving advice from a compensation consultant or other adviser, the compensation committee of a listed company will be required to take into consideration six specific factors, as well as all other factors relevant to an adviser's independence.

Foreign private issuers such as us will be exempt from these requirements if home country practice is followed. Bermuda law does not impose similar requirements, so we will not be required to implement the NYSE listing standards relating to compensation committees of domestic listed companies. All of the members of our compensation committee are independent, and the charter of our compensation committee does not require the compensation committee to consider the independence of any advisers that assist them in fulfilling their duties.

Additional audit committee functions

The NYSE standards require that audit committees of domestic companies to serve a number of functions in addition to reviewing and approving the company's financial statements, engaging auditors and assessing their independence, and obtaining the legal and other professional advice of experts when necessary. For instance, the NYSE Standards require that the audit committee meet independently with management in a separate session in order to maximize the effectiveness of the committee's oversight function. In addition, audit committees must obtain and review a report by the independent auditors describing the firm's internal quality-control procedures and any issues raised by these procedures. Finally, audit committees are responsible for designing and implementing an internal audit function that assesses the company's risk management processes and systems of internal control on an ongoing basis.

Foreign private issuers such as us are exempt from these additional requirements if home country practice is followed. Bermuda law does not impose similar requirements, and consequently, our audit committee does not perform these additional functions. Our Audit Committee is composed exclusively of independent auditors.

Miscellaneous

In addition to the above differences, we are not required to: make our audit and compensation committees prepare a written charter that addresses either purposes and responsibilities or performance evaluations in a manner that would satisfy the NYSE's requirements; acquire shareholder approval of equity compensation plans in certain cases; or adopt and make publicly available corporate governance guidelines.

We are incorporated under, and are governed by, the laws of Bermuda. For a summary of some of the differences between provisions of Bermuda law applicable to us and the laws applicable to companies incorporated in Delaware and their shareholders, See "Item 10. Additional Information—B. Memorandum of association and bye-laws."

ITEM 16H. Mine safety disclosure

Not applicable.

ITEM 17. **Financial statements**

We have responded to Item 18 in lieu of this item.

ITEM 18. **Financial statements**

Financial Statements are filed as part of this annual report, see pages 156 to 205 to this annual report.

ITEM 19. **Exhibits**

No.	Description
1.1	Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
1.2	Memorandum of Association (incorporated herein by reference to Exhibit 3.2 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
1.3	Current bye-laws (incorporated herein by reference to Exhibit 3.3 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
1.4	Form of amended and restated bye-laws (incorporated herein by reference to Exhibit 3.4 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
2.2	Indenture, dated September 21, 2017, among GeoPark Limited, the Bank of New York Mellon and Lord Securities Corporation.*
2.3	Contract of Pledge without Conveyance on Shares between GeoPark Latin America Limited Agencia en Chile and Lord Securities Corporation, dated September 21, 2017.*
2.4	Deed of Pledge of Membership Interest among GeoPark Latin America Coöperatie U.A., Stichting Collateral Agent Geopark and GeoPark Colombia Coöperatie U.A.*
4.1	Special Contract for the Exploration and Exploitation of Hydrocarbons, Fell Block, dated April 29, 1997, among the Republic of Chile, the Chilean Empresa Nacional de Petróleo (ENAP) and Cordex Petroleums Inc. (incorporated herein by reference to Exhibit 10.1 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.2	Exploration and Production Contract regarding exploration for and exploitation of hydrocarbons in the La Cuerva Block, dated April 16, 2008, between the Colombian Agencia Nacional de Hidrocarburos and Hupecol Caracara LLC (incorporated herein by reference to Exhibit 10.2 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.3	Exploration and Production Contract regarding exploration for and exploitation of hydrocarbons in the Llanos 34 Block, dated March 13, 2009, between the Colombian Agencia Nacional de Hidrocarburos and Unión Temporal Llanos 34 (incorporated herein by reference to Exhibit 10.3 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.4	Subscription and Shareholders Agreement, dated February 7, 2006, among the International Finance Corporation, GeoPark Holdings Limited, Gerald O'Shaughnessy and James F. Park (incorporated herein by reference to Exhibit 10.4 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.5	Shareholders' Agreement, dated May 20, 2011, among LG International Corporation, GeoPark Chile Limited Agencia en Chile and GeoPark Chile S.A. (incorporated herein by reference to Exhibit 10.7 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.6	Shareholders' Agreement, dated December 18, 2012, among LG International Corporation, GeoPark Chile Limited Agencia en Chile and GeoPark Colombia S.A. (incorporated herein by reference to Exhibit 10.9 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.7	Subscription Agreement, dated October 18, 2011, among LG International Corporation and GeoPark TdF S.A. (incorporated herein by reference to Exhibit 10.11 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.8	Shareholders' Agreement, dated October 4, 2011, among LG International Corporation, GeoPark TdF S.A. and GeoPark Chile S.A. (incorporated herein by reference to Exhibit 10.12 to the Company's Registration Statement on Form F-1 (File No. 333-191068) filed with the SEC on September 9, 2013).
4.9	Purchase and Sale Agreement for Natural Gas between GeoPark Chile Limited Agencia en Chile and Methanex Chile SpA. (incorporated herein by reference to Exhibit 10.15 to the Company's Registration Statement on Form F-1/A (File No. 333-191068) filed with the SEC on October 10, 2013). †
4.10	First Addendum and Amendment to Purchase and Sale Agreement for Natural Gas between GeoPark Chile Limited Agencia en Chile and Methanex Chile SpA. (incorporated herein by reference to Exhibit 10.16 to the Company's Registration Statement on Form F-1/A (File No. 333-191068) filed with the SEC on October 10, 2013). †
4.11	Second Addendum and Amendment to Purchase and Sale Agreement for Natural Gas between GeoPark Chile Limited Agencia en Chile and Methanex Chile SpA. (incorporated herein by reference to Exhibit 10.7 to the Company's Registration Statement on Form F-1/A (File No. 333-191068) filed with the SEC on September 26, 2013).
4.12	Third Addendum and Amendment to Purchase and Sale Agreement for Natural Gas between GeoPark Chile Limited Agencia en Chile and Methanex Chile SpA. (incorporated herein by reference to Exhibit 10.18 to the Company's Registration Statement on Form F-1/A (File No. 333-191068) filed with the SEC on October 10, 2013). †
4.13	Fourth Addendum and Amendment to Purchase and Sale Agreement for Natural Gas between GeoPark Chile Limited Agencia en Chile and Methanex Chile SpA. (incorporated herein by reference to Exhibit 10.19

No.	Description
	to the Company's Registration Statement on Form F-1/A (File No. 333-191068) filed with the SEC on October 10, 2013). †
4.14	Fifth Addendum and Amendment to Purchase and Sale Agreement for Natural Gas between GeoPark Chile Limited Agencia en Chile and Methanex Chile SpA. dated April 1, 2014. (incorporated herein by reference to Exhibit 4.23 to the Company's Annual Report on Form 20-F filed with the SEC on April 30, 2015). †
4.15	Sixth Addendum and Amendment to Purchase and Sale Agreement for Natural Gas between GeoPark Chile Limited Agencia en Chile and Methanex Chile SpA. dated May 1, 2015 (incorporated herein by reference to Exhibit 4.21 to the Company's Annual Report on Form 20-F filed with the SEC on April 15, 2016). †
4.16	Seventh Addendum and Amendment to Purchase and Sale Agreement for Natural Gas between GeoPark Chile Limited Agencia en Chile and Methanex Chile SpA. dated April 1, 2016 (incorporated herein by reference to Exhibit 4.21 to the Company's Annual Report on Form 20-F filed with the SEC on April 11, 2017). †
4.17	Contract for the sale and Purchase of Natural Gas 2017-2027 between GeoPark Fell SpA and Methanex Chile SpA dated March 31, 2017 (incorporated herein by reference to Exhibit 4.22 to the Company's Annual Report on Form 20-F filed with the SEC on April 11, 2017). †
4.18	Members' Agreement, dated January 8, 2014, among GeoPark Latin America Coöperatie U.A., GeoPark Colombia Coöperatie U.A. and LG International Corporation (incorporated herein by reference to Exhibit 10.20 to the Company's Registration Statement on Form F-1/A (File No. 333-191068) filed with the SEC on January 21, 2014).
4.19	Prepayment Agreement for an Amount of up to US$100,000,000, dated December 18, 2015, among C.I. Trafigura Petroleum Colombia SAS, GeoPark Colombia SAS and GeoPark Ltd. (incorporated herein by reference to Exhibit 4.25 to the Company's Annual Report on Form 20-F filed with the SEC on April 15, 2016).
4.20	Amendment Agreement No. 1 among GeoPark Colombia SAS, C.I. Trafigura Petroleum Colombia SAS and GeoPark Ltd. dated September 1, 2016 relating to the Prepayment Agreement dated December 18, 2015 (incorporated herein by reference to Exhibit 4.27 to the Company's Annual Report on Form 20-F filed with the SEC on April 11, 2017).
4.21	Amendment Agreement No. 2 among GeoPark Colombia SAS, C.I. Trafigura Petroleum Colombia SAS and GeoPark Ltd. dated December 16, 2016 relating to the Prepayment Agreement dated December 18, 2015 (incorporated herein by reference to Exhibit 4.28 to the Company's Annual Report on Form 20-F filed with the SEC on April 11, 2017).
4.22	Amendment Agreement No. 3 among GeoPark Colombia SAS, C.I. Trafigura Petroleum Colombia SAS and GeoPark Ltd. dated February 13, 2017 relating to the Prepayment Agreement dated December 18, 2015 (incorporated herein by reference to Exhibit 4.29 to the Company's Annual Report on Form 20-F filed with the SEC on April 11, 2017).
4.23	Asset Purchase Agreement between GeoPark Argentina Ltd. and Pluspetrol S.A., dated December 18, 2017.*
4.24	Purchase and Sale Agreement for Crude Oil and Condensate of Fell Block between Empresa Nacional del Petróleo (ENAP) and GeoPark Fell S.p.A., dated April 21, 2017.*
8.21	Subsidiaries of GeoPark Limited.*
12.1	Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002.*
12.2	Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002.*
13.1	Certification pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.*
13.2	Certification pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002.*
15.1	Consent of Price Waterhouse & Co. S.R.L., Argentina.*
15.2	Consents of DeGolyer and MacNaughton to use its report.*
99.1	Reserves Report of DeGolyer and MacNaughton dated February 15, 2018, for reserves in Chile, Colombia, Peru, Brazil as of December 31, 2017.*

* Filed with this Annual Report on Form 20-F.

† Confidential treatment of certain provisions of these exhibits has been requested with the SEC. Omitted material for which confidential treatment has been requested has been filed separately with the SEC.

Glossary of Oil and Natural Gas Terms

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

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

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

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

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

"bcm" means billion cubic meters.

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

"boepd" means barrels of oil equivalent per day.

"bopd" means barrels of oil per day.

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

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

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

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

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

"developed reserves" are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify developed reserves as undeveloped.

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

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

"E&P Contract" means exploration and production contract

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

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

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

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

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

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

"mboe" means one thousand barrels of oil equivalent.

"mcf" means one thousand cubic feet of natural gas.

"Measurements" include:

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

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

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

"mmboe" means one million barrels of oil equivalent.

"mmbtu" means one million British thermal units.

"NYMEX" means The New York Mercantile Exchange.

"net acres" means the percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has a 50% interest in 100 acres owns 50 net acres.

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

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

"proved developed reserves" means those proved reserves that can be

expected to be recovered through existing wells and facilities and by existing operating methods.
"proved reserves" means estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be economically recoverable in future years from known reservoirs under existing economic and operating conditions, as well as additional reserves expected to be obtained through confirmed improved recovery techniques, as defined in SEC Regulation S-X 4-10(a)(2).
"proved undeveloped reserves" means are those proved reserves that are expected to be recovered from future wells and facilities, including future improved recovery projects which are anticipated with a high degree of certainty in reservoirs which have previously shown favorable response to improved recovery projects.
"reasonable certainty" means a high degree of confidence.
"recompletion" means the process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
"reserves" means estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, a revenue interest in the production, installed means of delivering oil, gas, or related substances to market, and all permits and financing required to implement the project.
"reservoir" means a porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
"royalty" means a fractional undivided interest in the production of oil and natural gas wells or the proceeds therefrom, to be received free and clear of all costs of development, operations or maintenance.
"service well" means a well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation, or injection for in-situ combustion.
"shale" means a fine grained sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers. Shale can include relatively large amounts of organic material compared with other rock types and thus has the potential to become rich hydrocarbon source rock. Its fine grain size and lack of permeability can allow shale to form a good cap rock for hydrocarbon traps.
"spacing" means the distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g. , 40-acre spacing, and is often established by regulatory agencies).
"spud" means the very beginning of drilling operations of a new well, occurring when the drilling bit penetrates the surface utilizing a drilling rig capable of drilling the well to the authorized total depth.
"stratigraphic test well" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) exploratory-type, if not drilled in a proved area, or (ii) development-type, if drilled in a proved area.
"tcm" means trillion cubic meters.
"undeveloped reserves" are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulation, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recover, or (4) where a relatively large expenditure (e.g. , when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.
"unit" means the joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
"wellbore" means the hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.
"working interest" means the right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.
"workover" means operations in a producing well to restore or increase production.

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

GEOPARK LIMITED
By: /s/ James F. Park
Name: James F. Park
Title: Chief Executive Officer and Deputy Chairman

Date: April 11, 2018

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 Luis Mirazon

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)**

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 difference	(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 163 to 205 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 163 to 205 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 Income 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 163 to 205 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) / from 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 163 to 205 are an integral part of these 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.

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.

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.

• 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 recognises the non-monetary asset or non-monetary liability arising from the payment or receipt of advance consideration. It is effective for annual periods beginning on January 1, 2018. The Group estimates that these interpretations 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.

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.

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).

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.

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.

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.

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.

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.

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.

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.

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).

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.

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.

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.

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.

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

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:

– 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

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 impaiment 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).

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 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.

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			
Oil and gas properties	2017	2016	2015
Production facilities and machinery	57,725	61,080	84,849
Furniture, equipment and vehicles	14,558	10,788	15,467
Buildings and improvements	1,948	2,702	2,850
Depreciation of property, plant and equipment [(a)]	844	920	874
	75,075	**75,490**	**104,040**
Related to:			
Productive assets			
Administrative assets	72,283	71,868	100,316
Depreciation total [(a)]	2,792	3,622	3,724
	75,075	**75,490**	**104,040**

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**

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

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 costs

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 costs	(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 in 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.

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 are 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.

Tax reforms in 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**

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 loss (profit)	**48,016**	**(36,524)**	**(285,768)**
Income tax calculated at domestic tax rates applicable to Profit (Losses) in the respective countries	(31,107)	(809)	62,589
Tax losses where no deferred income tax 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.

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**

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) Earnings 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**

[(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**

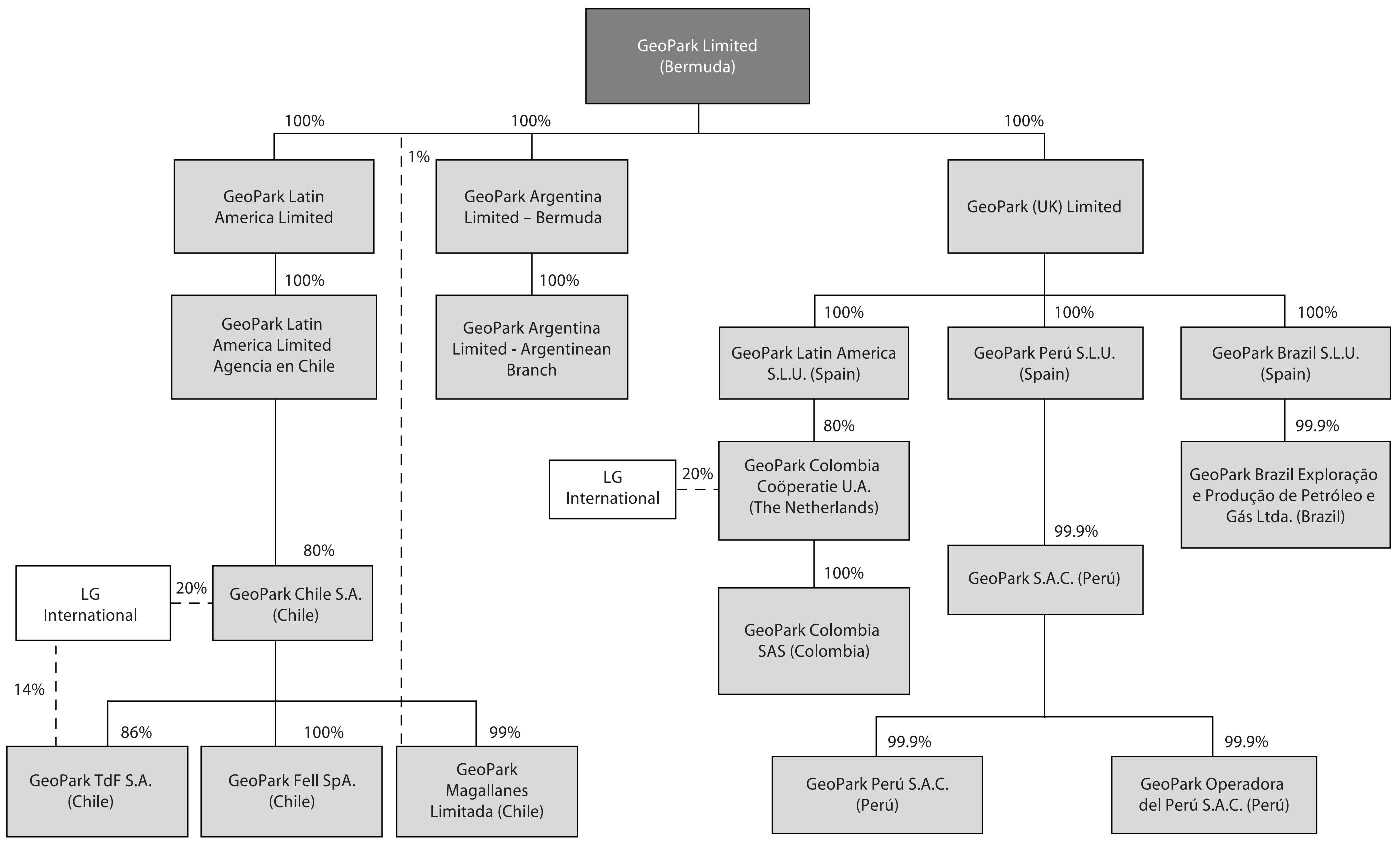
As of 31 December 2017, there were two exploratory wells that have been capitalised for a period less than a year amounting to US$ 4,488,000 and two exploratory wells that have been capitalised for a period over a year amounting to US$ 6,116,000.

(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.

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. 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

	Assets as per statement of financial position	
Amounts in US$ '000	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.

	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.

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**	**-**

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.

(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 counterparty credit risk and are within level 2 of the fair value hierarchy. The fair value of the remaining financial instruments is determined using discounted cash flow analysis. All of the resulting fair value estimates are included in level 2.

(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 2016			**60.6**	**61**

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.

[(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.

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:

Year of issuance	Awards at the beginning	Awards granted in the year	Awards forfeited	Awards exercised	Awards at year end	Charged to net loss / profit 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)
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

Subsidiary / Joint operation	Interest	PP&E E&E Assets	Other Assets	Total Assets	Total Liabilities	NET ASSETS/ (LIABILITIES)	Revenue	Operating (loss) profit
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	Table B
°API	Po (US$/barrel)	WTI (P)	S
>29°	30.22	Po < P < 2Po	30%
>22°<29°	31.39	2Po < P < 3Po	35%
>15°<22°	32.56	3Po < P < 4Po	40%
>10°<15°	46.50	4Po < P < 5Po	45%
		5Po < P	50%

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.

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.

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.

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.

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).

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.

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.

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.

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.		
	Low price (15%)	Middle price (60%)	High price (25%)
Year			
2018	64.9	64.9	64.9
2019	53.2	62.5	71.7
2020	54.4	63.9	73.4
Over 2021	54.3	63.7	73.2

[(a)] The percentages indicated between brackets represent the Company 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	Perú	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	Perú	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	Perú	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.

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.

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 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**

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 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).

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
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	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**	**76,673.0**

[(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).

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 4,101.5 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
Purchases 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.

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.

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.

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**

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.

Certification by the Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley act of 2002

I, James F. Park, certify that:

1. I have reviewed this annual report on Form 20-F of GeoPark Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;

4. The company's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a 15(f) and 15d 15(f)) for the company and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

5. The company's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the company's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the company's internal control over financial reporting.

Date: April 11, 2018
James F. Park
Chief Executive Officer
(Principal Executive Officer)

Certification by the Principal Financial Officer Pursuant to Section 302 of The Sarbanes-Oxley Act of 2002

I, Andrés Ocampo, certify that:

1. I have reviewed this annual report on Form 20-F of GeoPark Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;

4. The company's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a 15(f) and 15d 15(f)) for the company and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

5. The company's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the company's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the company's internal control over financial reporting.

Date: April 11, 2018
Andrés Ocampo
Chief Financial Officer
(Principal Financial Officer)

Certification by the Principal Executive Officer Pursuant to 18 U.s.c. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley act of 2002

The certification set forth below is being submitted in connection with the Annual Report on Form 20-F of GeoPark Limited (the "Company") for the fiscal year ended December 31, 2017 (the "Report"), I, James F. Park, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

1. the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: April 11, 2018
James F. Park
Chief Executive Officer
(Principal Executive Officer)

Certification by the Principal Executive Officer Pursuant to 18 U.s.c. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley act of 2002

The certification set forth below is being submitted in connection with the Annual Report on Form 20-F of GeoPark Limited (the "Company") for the fiscal year ended December 31, 2017 (the "Report"), I, Andrés Ocampo, certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge:

1. the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: April 11, 2018
Andrés Ocampo
Chief Financial Officer
(Principal Financial Officer)

BOARD OF DIRECTORS

Gerald E. O'Shaughnessy | Chairman
Mr. O'Shaughnessy has been our Chairman and a member of our board of directors since he co-founded the company in 2002. Following his graduation from the University of Notre Dame with degrees in government (1970) and law (1973), Mr. O'Shaughnessy was engaged in the practice of law in Minnesota. Mr. O'Shaughnessy has been active in the oil and gas business over his entire business career, starting in 1976 with Lario Oil and Gas Company. He later formed The Globe Resources Group, a private venture firm whose subsidiaries provided seismic acquisition and processing, well rehabilitation services, logistical operations and submersible pump works for Lukoil and other companies active in Russia during the 1990s. Mr. O'Shaughnessy is also founder of BOE Midstream, which owns and operates the Bakken Oil Express, a crude by rail transloading and storage terminal in North Dakota, serving oil producers and marketing companies in the Bakken Shale Oil play. Mr. O'Shaughnessy has also served on a number of non-profit boards of directors, including the Board of Economic Advisors to the Governor of Kansas, the I.A. O'Shaughnessy Family Foundation, the Wichita Collegiate School, the Institute for Humane Studies, The East West Institute and The Bill of Rights Institute, the Timothy P. O'Shaughnessy Foundation and is a member of the Intercontinental Chapter of Young Presidents Organization and World Presidents' Organization.

Pedro E. Aylwin | Executive Director
Mr. Aylwin has served as a member of our board of directors since July 2013 and as our Director of Legal and Governance since April 2011. From 2003 to 2006, Mr. Aylwin worked for us as an advisor on governance and legal matters. Mr. Aylwin holds a degree in law from the Universidad de Chile and an LLM from the University of Notre Dame. Mr. Aylwin has extensive experience in the natural resources sector. Mr. Aylwin is also a partner at the law firm Aylwin, Mendoza, Luksic, Valencia Abogados in Santiago, Chile, where he represented mining, chemical and oil and gas companies in numerous transactions. From 2006 until 2011, he served as Lead Manager and General Counsel at BHP Billiton, Base Metals, where he was in charge of legal and corporate governance matters on BHP Billiton's projects, operations and natural resource assets in South America, North America, Asia, Africa and Australia.

Carlos A. Gulisano | Non-Executive Director
Mr. Gulisano has been a member of our board of directors since June 2010. Dr. Gulisano holds a bachelor's degree in geology, a post-graduate degree in petroleum engineering and a PhD in geology from the University of Buenos Aires and has authored or co-authored over 40 technical papers. He is a former adjunct professor at the Universidad del Sur, a former thesis director at the University of La Plata, and a former scholarship director at the national technology research council in Argentina. Dr. Gulisano is a respected leader in the fields of petroleum geology and geophysics in South America and has over 35 years of successful exploration, development and management experience in the oil and gas industry. In addition to serving as an advisor to GeoPark since 2002 and as Managing Director from February 2008 until June 2010, Dr. Gulisano has worked for YPF, Petrolera Argentina San Jorge S.A. and Chevron San Jorge S.A. and has led teams credited with significant oil and gas discoveries, including those in the Trapial field in Argentina. He has worked in Argentina, Bolivia, Peru, Ecuador, Colombia, Venezuela, Brazil, Chile and the United States.

Juan Cristóbal Pavez | Non-Executive Director
Mr. Pavez has been a member of our board of directors since August 2008. He holds a degree in commercial engineering from the Pontifical Catholic University of Chile and an MBA from the Massachusetts Institute of Technology. He has worked as a research analyst at Grupo CB and later as a portfolio analyst at Moneda Asset Management. In 1998, he joined Santana, an investment company, as Chief Executive Officer, where he focused mainly on investments in capital markets and real estate. While at Santana, he was appointed Chief Executive Officer of Laboratorios Andrómaco, one of Santana's main assets. Since 2001, he has served as Chief Executive Officer at Centinela, a company with a diversified global portfolio of investments, with a special focus in the energy industry, through the development of wind parks and run-of-the-river hydropower plants. Mr. Pavez is also a board member of Grupo Security, Vida Security and Hidroelétrica Totoral and founder board member of several companies, including Quintec, Enaex, CTI and Frimetal.

Robert A. Bedingfield | Non-Executive Director
Mr. Bedignfield has been a member of our board of directors since March 2015. He holds a degree in Accounting from the University of Maryland and is a Certified Public Accountant. Until his retirement in June 2013, he was one of Ernst & Young's most senior Global Lead Partners with more than 40 years of experience, including 32 years as a partner in Ernst & Young's accounting and auditing practices, as well as serving on Ernst & Young's Senior Governing Board. He has extensive experience serving Fortune 500 companies; including acting as Lead Audit Partner or Senior Advisory Partner for Lockheed Martin, AES, Gannett, General Dynamics, Booz Allen Hamilton, Marriott and the US Postal Service. Since 2000, Mr. Bedingfield has been a Trustee, and at times an Executive Committee Member, and the Audit Committee Chair of the University of Maryland at College Park Board of Trustees. Mr. Bedingfield served on the National Executive Board (1995 to 2003) and National Advisory Council (since 2003) of the Boy Scouts of America. Since 2013, Mr. Bedingfield has also served as Board Member and Chairman of the Audit Committee of NYSE-listed Science Applications International Corp (SAIC).

Jamie B. Coulter | Non-Executive Director
Mr. Coulter has been a member of our board of directors since May 2017. He currently serves as Chairman and CEO of Coulter Enterprises Inc., a private investment firm and has been an investor in and supporter of GeoPark since 2006. He built and became the CEO of Lone Star Steakhouse & Saloon, a company that was awarded IPO of the year and Forbes Magazine #1 Best Small Company in America for 3 consecutive years. He developed and operated Pizza Hut and Kentucky Fried Chicken restaurants and became the largest Pizza Hut franchisee, was inducted to the Pizza Hut Hall of Fame, and was named the Restaurants & Institutions CEO of the year. Mr. Coulter has both operating and investment experience in the oil and gas business, including, the founding of Sunburst Exploration, a US upstream oil and gas company and also has a successful track record as an oil and gas investor in the North American shale plays.
Mr. Coulter currently serves as a Director of the Federal Law Enforcement Foundation; Director of Jimmy Johns, LLC; Director of Realm Cellars; Director of Cirq Estates, LLC; Director of KB Wines, LLC; Member of the Board of Trustee for HCA Wesley Medical Center and Member of the Texas Heart Institute Foundation Board.

Constantin Papadimitriou | Non-Executive Director
Mr. Papadimitriou has been a member of our board of directors since May 2018. Mr. Papadimitriou holds an Economics and Finance degree from Geneva University and post graduate Diploma in European Studies also from Geneva University. Mr. Papadimitriou is a respected and successful international investor and businessman, with more than 30 years of investment experience in global capital markets and in resource and industrial projects. Mr. Papadimitriou was one of the original "friends and family" investors in GeoPark in its early days in 2004. Mr. Papadimitriou is currently CEO of General Oriental Investments S.A., the Investment Manager of the Cavenham Group of Funds. Previously he was CEO of Cavamont Geneva. During his tenure at the Cavamont group, Mr. Papadimitriou was responsible for Treasury Management, the Private Equity Portfolio as well as representing the group on the Boards of associated companies including investments in the oil and gas, mining, real estate and gaming sectors (including Basic Petroleum, a Nasdaq-listed Guatemalan oil and gas company). Mr. Papadimitriou is also founding partner of Diorasis International, a company focusing on investments in Greece and the broader Balkans and he also chairs the Greek language school of Geneva and Lausanne.

James F. Park | Chief Executive Officer and Deputy Chairman
Mr. Park has served as our Chief Executive Officer and as a member of our board of directors since co-founding the Company in 2002 and has led the Company´s expansion into Chile, Argentina, Colombia, Brazil and Peru. He has extensive experience in all phases of the upstream oil and gas business, with a strong background in the acquisition, implementation and management of international joint ventures in North America, South America, Asia, Europe and the Middle East. He holds a degree in geophysics from the University of California at Berkeley and has worked as a research scientist in earthquake studies at the University of Texas. Mr. Park helped pioneer the development of commercial oil and gas production in Central America, as a senior executive of Basic Resources International where he remained as a board member until the company was successfully sold in 1997. Mr. Park has experience in the development of grass-roots exploration activities, drilling and production operations, surface and pipeline construction and crude oil marketing and transportation, and with legal and regulatory issues, and raising substantial investment funds. Mr. Park is also a member of the board of directors of Energy Holdings and has served on various non-profit organizations, including as a board member of S.E.E. International. Mr. Park is a member of the AAPG and SPE and has lived in Latin America since 2002.

CORPORATE MANAGEMENT TEAM


JAMES F. PARK
Chief Executive Officer


AUGUSTO ZUBILLAGA
Chief Operating Officer


ANDRÉS OCAMPO
Chief Financial Officer


PEDRO E. AYLWIN
Legal & Governance


MARCELA VACA
Colombia


ALBERTO MATAMOROS
Argentina, Chile


BARBARA BRUCE
Peru


LIVIA VALVERDE
Brazil


SALVADOR MINNITI
Exploration


CARLOS MURUT
Reserves & Development


JUAN CARLOS FERRERO
Operations


HORACIO FONTANA
Drilling & Workover


AGUSTINA WISKY
Capacities


GUILLERMO PORTNOI
New Business


STACY STEIMEL
Shareholder Value

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