PETRONOR E&P

PROGRESSING OPPORTUNITIES

Annual Report 2019

SUSTAINABLE RESOURCE DEVELOPMENT

PetroNor E&P, listed on the Oslo Axess (PNOR), is an independent oil and gas company led by an experienced board and management team, with substantial experience in oil and gas exploration, appraisal, development and production.

PetroNor E&P listed on Oslo Axess 12 September 2019

Contents

Highlights

2019 highlights and subsequent events

- Following our entry in 2017 into a producing asset in West Africa, 2019 has been a year to cement our success and focus on further expansion through the merger between the former African Petroleum Corporation Ltd and PetroNor, and to increase activity in West Africa, primarily in Nigeria.
- Since our acquisition of the interest in the PNGF Sud licence, the licence has seen both production increase and a reduction in operating cost.
- Restructuring of the combined group to streamline the organisation to reduce overhead costs and grow technical excellency.
- Focus on bringing a solution to the Gambia and Senegal arbitration processes as well as expanding to Nigeria.

Assets

Republic of Congo (Brazzaville)

- 10.5% indirect participation interest in the licence group of PNGF Sud (Tchibouela II, Tchendo II and Tchibeli-Litanzi II) through Hemla E&P Congo SA.
- The Group holds the right to negotiate, in good faith, the terms of the adjacent licence of PNGF Bis and a 14.7% indirect participation.

Nigeria

- Signed a transaction with Panoro Energy to acquire their 6.052% nominal shareholding in the Aje Field and to establish a joint venture with Yinka Folawiyo Petroleum ("YFP") which will give PetroNor a 13.1% economic interest in the asset.

Senegal and The Gambia

- Though currently in arbitration, the Company reserves its rights in the exploration blocks Rufisque Offshore Profond and Senegal Offshore Sud Profond in Senegal and A1 & A4 in The Gambia.

EBITDA (USD)
49.00m
-7.7% (2018: 53.10m)

EBIT (USD)
45.77m
-8.3% (2018: 49.89m)

Net profit/(loss) (USD)
(5.76)m
(2018: 17.06m)

10.8 MMbbl
2P Reserves
(2018: 8.5MMbbl)

7.3 MMbbl
2C Contingent Resources
(2018: 7.6MMbbl)

4.9 bnbbl
net unrisked prospective resources[1]

~2,640 bbl/d
net oil production[2]

1. ERC Equipoise, assets in dispute.
2. Includes 314 bbl/d from OML 113 interest which is subject to contract completion.

OUR DIVERSIFIED PORTFOLIO

Our mission

Our mission is to generate shareholder value by leveraging the technical and commercial skillset of the Company to enhance its reserve base, production and cash flow. PetroNor E&P is committed to the highest standards of corporate governance, transparent stakeholder engagement and operational excellence.

Our strategic vision is to steadily build the company into a fullcycle, Africa-focused exploration and production company with an emphasis on producing and developing assets with upside potential. To reflect growth ambitions, the Board has set a target of achieving reserves of 300 mmboe and production of 30,000 barrels of oil equivalent per day (boepd) in the next three years.

What we do

We are an independent oil and gas exploration and production company with licences in four countries offshore; West Africa-Republic of Congo, Senegal, The Gambia and Nigeria. The Company has amassed a diverse and high-quality portfolio comprising economically-robust production, development upside, and high-impact exploration.

CONGO-B

Congo Brazzaville is a core country for PetroNor, both for production as well as for regional expansion.

PNGF Sud is operated by Perenco – a world leading company with +400,000 bbl/d. Perenco has specialized in low-cost tail production assets like PNGF Sud.

Production in PNGF Sud has increased 50% since its takeover, combined with significant cost improvements.

Several mature assets are coming to the market over the new few years, giving a significant growth opportunity for PetroNor.

Production (net)

2,327 bbl/d

2P Resources (net)

10.8 MMbbl

2C Resources (net)

7.3 MMbbl

4 fields: 10.5% Indirect Interest

Offices

The Company has its registered address in Perth, Australia. The Group maintains headquarters in London, and operational offices in Oslo, Nicosia and Abu Dhabi.

NIGERIA

Nigeria is a core country for PetroNor due to its significant number of undeveloped assets.

PetroNor has created a joint venture together with the operator' YFP for the revitalisation of the Aje field.

Current oil and condensate production at the Aje field to be increased up to 8,000 bbl/d with the liquids only, and 20,000 boepd including the gas development.

PetroNor is seeing a significant number of opportunities for merger and acquisition (M&A) in Nigeria.

Production (net)

314 bbl/d

2C Resources (net)

18.7 MMbbl

1 field: 13.08% Initial Economic Interest

SENEGAL

Senegal has an exciting exploration potential that includes the discovery of the world-class Sangomar field adjacent to the licensed ROP block.

Net unrisked Prospective Resources

1,779 MMbbl

2 licences: 14,216km² (net) 90% working interest

THE GAMBIA

The Gambia is within the same proven play trend as Senegal and the Sangomar field, a play which is expected to extend southward into The Gambia.

Net unrisked Prospective Resources

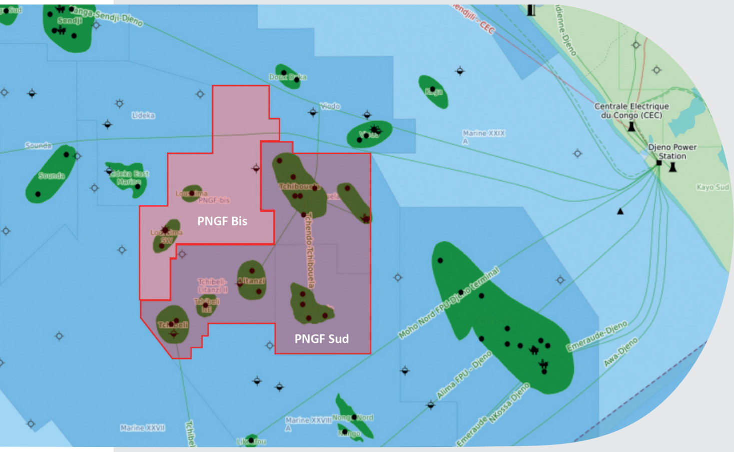
3,079 MMbbl

2 licences: 2,672km² (net) 100% working interest

Business development
Focusing on opportunities onshore and offshore sub-Saharan Africa

CONGO-BRAZZAVILLE

The Republic of Congo (Congo-Brazzaville) is the third-largest oil producer in sub-Saharan Africa, after Nigeria and Angola, with an output of around 350,000 bbl/d. The majority of the production in Congo is located offshore, with approximately half in deep water.



Operational gross production

21,920 bbl/d

(2018: 20,326 bbl/d)

2P Reserves and resources (net)

10.8 MMbbl

(2018: 8.6 MMbbl)

2C Reserves and resources (net)

7.3 MMbbl

(2018: 7.6 MMbbl)

PNGF Sud

Licence overview

In 2016 production rates were less than 15,000 bbl/d when Total exited and the current partnership took over the licence with Perenco as operator. Since then, low-cost brick by brick improvements via workovers and production process improvements have resulted in today's production levels of circa 23,000 bbl/d.

Net interest

10.5%

Reserves growth through infill drilling 2020-2021 (Litanzi and Tchendo)

Litanzi:

- Jackup acquired and modified with simple processing – oil and water to Tchendo
- Two infill producers and two infill injectors targeting upswept fault terraces
- Estimated improved recovery of 8-12 MMbbl
- Total expected CAPEX of USD 100 million gross (USD 10.5 million net)
- Economics attractive for reserve additions with between 8-13 USD/bbl of CAPEX

Tchendo:

- Wellhead platform with platform or tender rig installed, allowing for expansion of the infill programme
- Initially six infill producers are planned at Tchendo at c. USD 5 million/well
- Total expected CAPEX USD 84 million gross with incremental recovery of 5-6 MMbbl corresponding to 12-17 USD/bbl

PNGF Bis

Licence overview

PNGF Bis is located next to PNGF Sud and contains two discoveries from 1985-1991 (Loussima SW and Loussima). The partnership has a right to negotiate the licence on given terms with possible conclusion in 2020. The three discovery wells tested from 1,150 to 4,700 bbl/d of light, good quality oil. Perenco has recently made a detailed reinterpretation, 3D modelling and facilities study for the Loussima SW discovery, yielding >100 MMbbl of in-place resources and a possible lie-back to Tchibouela.

AGR Petroleum Services warrants 2C resources of 29 MMbbl in a 2019 CPR including verification of the tie-back scenario given above.

Net interest

14.7%

Licence activity

- Low Cost Production – Lifting Cost (OPEX) 12.5 USD/bbl
- Net production of 2,301 bbl/d (2019 average)
- Tchibouela East production restarted in 2019; further growth expected
- New high-quality 3D reservoir models now being utilised for field management
- Infill drilling programmes at Litanzi and Tchendo will target further production increases
- Cost-effective (<2 USD/bbl) workover programme to enhance production
- Investment in surface equipment to improve processes and support growth
- Rerouted Tchibeli production to reduce third party processing tariffs
- Significant further enhancement potential (currently 23% recovery only)

Producing wells

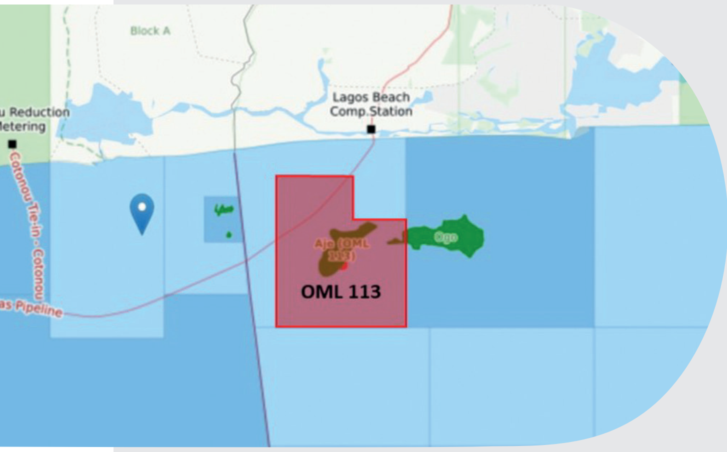
61

Licence activity

- Proven reserves in Loussima SW to be appraised and developed in a phased approach to manage uncertainty
- Early production scheme planned, prior to decision to proceed with full development
- Development plan is to use low-cost jack-up with minimum topside upgrading and 11km catenary pipeline to Tchibouela
- Significant potential upside from Loussima discovery of 46° API oil to be appraised

NIGERIA

Nigeria is one of the most petroleum-rich nations in the world. Nearly all of the country's primary reserves are concentrated in and around the Niger Delta. Nigeria is one of the few major oil-producing nations still capable of increasing its oil output.



Estimated gross production for 2020

2,300 bbl/d

(2018: 2,967 bbl/d)

2C Resources (net)

18.7 MMbbl (17.4%)

Nominal interest: 34.0%
Economic interest: 13.1%
Economic interest new development: 17.4%

OML 113 (Aje Field)

Licence overview

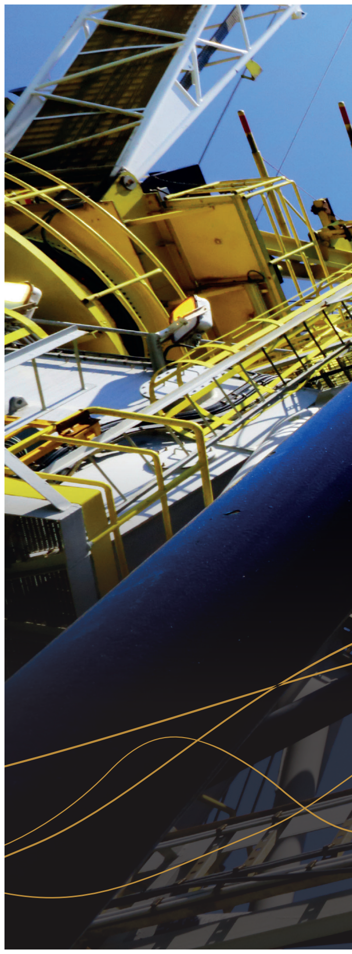
The Aje Field was discovered after drilling of the Aje-1 well in 1996. The OML 113 block covers 835km^2 with water depths ranging from 100m to 1,500m. Five wells have been drilled; oil production is from Turonian and Cenomanian age reservoirs. PetroNor acquired the Panoro equity share in the field in 2019. An SPV has been setup with the operator YFP whereby PetroNor have joint technical operatorship (subject to final approval by the Nigerian government). Overlying the Turonian oil rim is a significant gas-condensate discovery which has not been developed. Gas produced from the field is flared.

Forward plan

The Nigerian government encourages stop-flaring programmes and the country is in dire need of electrical power. Through the entry to Aje as joint operator, PetroNor will target the gas, condensate and oil in a low-risk development plan. Wet-gas will be brought to shore for further processing and extraction of LPG.

Net interest

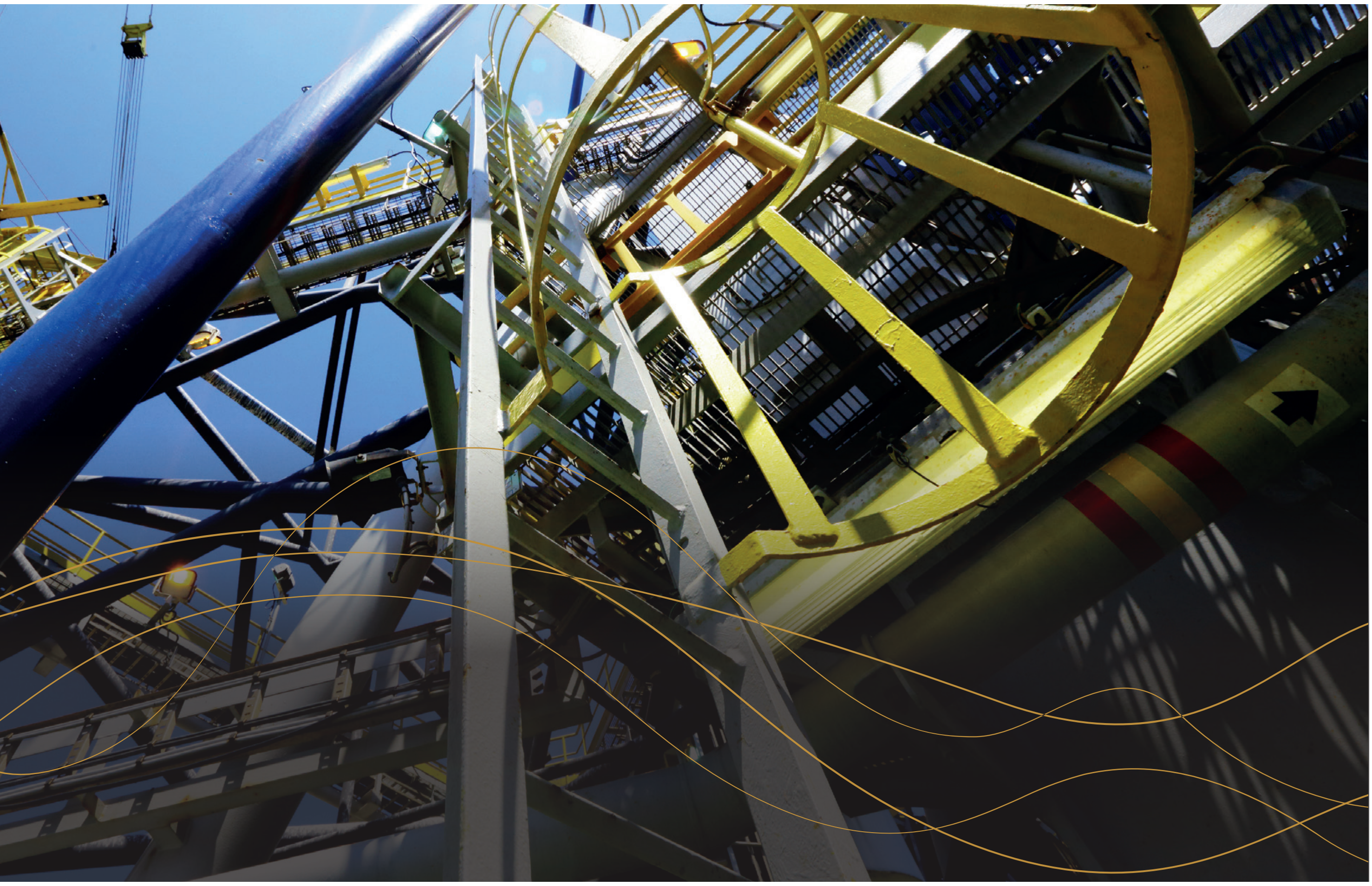
13.1%



Licence Activity

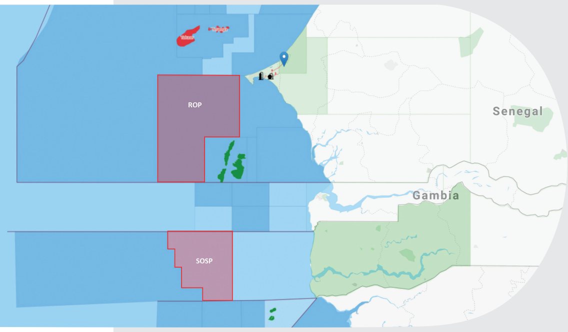
The current partnership has invested significantly into the current drilling and development. With the current (low) production, the only sustainable future is to invest to target the already-discovered oil and gas volumes in Aje. With different partnership economics, the partners have struggled to agree on a suitable way forward. PetroNor offers a robust development solution to the partnership.

- The flared gas will be reinjected to stop the resource waste and allow for a gas recycling process
- Condensate will be stripped from the gas produced offshore and "dry" gas will be reinjected until gas commercialisation is available
- While drilling gas well locations, additional oil targets will be appraised
- Gas commercialisation options include direct sales of rich gas or further processing in a purpose-built gas plant to extract additional liquids (LPG and condensate) before the gas is sold to the local market.



SENEGAL & THE GAMBIA

The Company reserves its rights to 90% operating working interest in the exploration blocks Rufisque Offshore Profond ("ROP") and Senegal Offshore Sud Profond ("SOSP") comprising 14,216 km².



Net unrisked prospective resources

1,779 MMbbl

Senegal

Licence overview

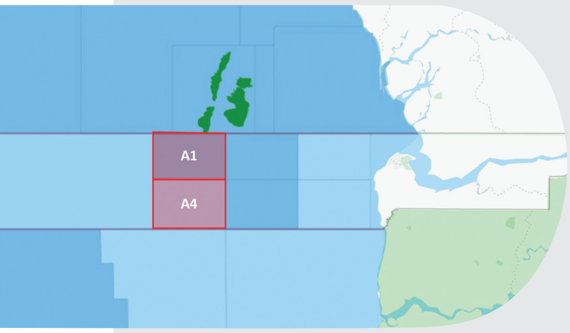
The award of the ROP licence to Total in February 2017 is the subject of ongoing international arbitration. PetroNor reserves its rights to 90% equity in the ROP block. Petronas farmed-in in August 2018 and Total (60% Operator), Petronas (30%) and Petrosen (10%) drilled the Jamm-1X well in August 2019 (after acquisition, and processing of a large 3D seismic survey). Jamm-1X was classed as a non-commercial oil discovery (successfully extending the oil trend northward and further basinward).

In May 2020, the Company reached an agreement with the Government of Senegal to suspend the arbitration related to the Rufisque Offshore Profond and Senegal Offshore Sud Profond licence areas for a period of six months, with a view to reaching a satisfactory outcome for all parties. A formal request was lodged with the International Centre for Settlement of Investment Disputes (ICSID) to suspend the process.

Net interest

90%

The Company reserves its rights to the 100% operating working interest in the offshore licenses A1 and A4, comprising 2,672 km².



Net unrisked prospective resources

3,079 MMbbl

The Gambia

Licence overview

The award of Block A1 to BP in April 2019, is disputed by PetroNor and is the subject of ongoing international arbitration. PetroNor continues to reserve its rights in relation to both the A1 and A4 licenses and will continue with its efforts to protect its interest through the ongoing arbitration process.

BP plans to conduct an environmental assessment followed by a two-year drilling period in Block A1. The adjacent A2/A5 acreage is operated by Far Ltd (50%), in partnership with Petronas (50%). The Samo-1 well was drilled in late 2018; though a dry hole, it had encouraging shows at multiple levels. Increased interest from large International Companies and ongoing work commitments verify the high potential of this acreage. PetroNor looks forward to the resolution of the ongoing arbitration.

Net interest

100%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FALL

CLEAR STRATEGIC VISION

Eyas Alhomouz | Chairman

I am delighted to provide my first annual statement to PetroNor E&P's shareholders and our wider stakeholders. Last year was a year of transformation and inception, as PetroNor E&P was formed through the combination of African Petroleum and PetroNor in an all-share transaction.

"NEW BUSINESS DEVELOPMENT WILL BE AT THE HEART OF OUR STRATEGIC EXECUTION, AS WE SEEK ASSETS THAT DIVERSIFY OUR PORTFOLIO."

The combination has a strategic vision to develop into a material full-cycle oil and gas company. The rationale for the combination was clear for both parties and the Company today is well-positioned to leverage its existing platform to achieve scale, deliver sustainable value and establish itself as a leading independent E&P focused on Africa.

The enlarged group is underpinned by cash flow from an economically-robust asset base in Congo, and has the financial stability, and enhanced profile and network, to better-pursue satisfactory outcomes from the ongoing arbitration processes related to the licences in Senegal and The Gambia. It has also created a Board and management team with a diverse skillset comprising technical, commercial and financial expertise, with a proven track record for value creation and M&A execution. Leveraging the deep technical expertise of the management team to identify and exploit value-realisation opportunities from undeveloped or underperforming assets remains a core aspect of the growth strategy and, we believe, a critical element of PetroNor E&P's investment case.

The high-quality, low-risk and long-life asset base in Congo-Brazzaville continues to perform strongly, and provides the Company with robust cash flow from net working interest production of 2,301 bbl/d (average for the year). The asset has robust economics, remaining cash-flow positive down to USD 20 Brent, meaning it remains sustainable in the current low oil-price environment. Alongside our partners, the joint venture continues the optimisation of the field, both through low-cost intervention programmes as well as a new drilling programme. PNGF Sud, with its ~2bn bbl stock tank original oil-in-place (STOOIP) and a current average recovery factor of ~23%, still has significant potential for increased oil recovery.

In November, the Company announced a significant increase in 2P Reserves from PNGF Sud. An independent evaluation by AGR Petroleum Services AS ("AGR") of the producing fields confirmed the remaining net 2P oil reserves net to PetroNor (corrected for actual 2019 production to 1.1.2020) to be 10.76 MMbbl, representing a 26% increase compared to the previous year. This independent evaluation confirms the quality of the asset and the, as yet unrealised, core value associated with PetroNor E&P's indirect interest in the assets.

Following the formal completion of the merger in late August, the Company has proactively sought to engage with the relevant authorities in Senegal and The Gambia with a view to finding middle ground that is beneficial to all parties and avoids a prolonged and costly legal process through to completion. The situation regarding these licences remains complex and the outcome remains uncertain. Suffice to say, the Board is fully focused on achieving an outcome that is in the best interest of the Company's shareholders and this is front and centre of all decision-making associated with these assets.

Our strategic vision is clear; to steadily build the company into a full-cycle, Africa-centric E&P focusing on producing assets with upside and development of stranded assets. New business development will be at the heart of our strategic execution, as we seek assets that diversify our portfolio, and provide us with an opportunity to leverage our deep technical and commercial expertise to realise maximum value from assets.

In this regard, we were pleased to have announced a compelling first transaction rapidly after completing the merger. The acquisition of Panoro Energy's interest in OML 113, offshore Nigeria, is consistent with our strategy and provides us with additional cash flow, but more importantly an opportunity to unlock the true potential of this asset through partner alignment and technical execution. Nigeria is a country with an abundance of opportunities and a jurisdiction in which PetroNor E&P has extensive experience and network, and we continue to screen multiple opportunities in the country. Having subsequently signed an investment and shareholders' agreement with the OML 113 Operator, Yinka Folawiyo Petroleum ("YFP"), we now await final approvals from the relevant authorities, after which we will commence work with our partners as we seek to revitalise and further develop OML 113 and the Aje oil and gas field.

As an established and growing E&P, sustainability is a key consideration, both in terms of our business and our operating footprint. Global climate change has, quite rightly, become a more prominent theme for the industry, and investors are increasingly conscious of the ethical impact of their investments. As such, Environmental, Social and Governance ("ESG") has become a highly-relevant topic and our management and Board are undertaking a review of their activities in each of these categories to ensure the Company is operating at the highest industry standards and meeting shareholder expectations in this regard.

Following completion of the merger, the Board has undertaken a review to ensure the corporate structure is fit for purpose. Cost discipline is a fundamental driver for our business, and we have subsequently considered all areas where we can deliver cost savings without impacting the effectiveness of the business. We have successfully reduced overheads by reducing the size of the Board and management team; and will seek to deliver further cost savings this year through corporate initiatives, including a reduction in salaries and expenses, and a likely domiciliation to Europe. I would like to thank all the Directors who have left the Company in recent months, and extend particular thanks to both Jens Pace and Steve West who relinquished their roles as CEO and CFO respectively post period. The current structure of the Board and management team is better-suited for a company of our size, and we retain a deep and diverse skillset that will enable us to deliver on our strategic objectives.

Through the first quarter of 2020, the market conditions for the sector deteriorated rapidly due to a combination of global market-share disputes and the worrying impact of Coronavirus on international demand for hydrocarbons. The result has been a drastic decline in commodity pricing that has sent shockwaves through the industry and created uncertainty over CAPEX budgets and project-viability. In these times of uncertainty, it's more important than ever for companies to show financial discipline at all levels of the business. The Board will continue to drive down overheads and work with JV partners at the producing assets in Congo to ensure the sustainable economic robustness of the assets in a lower-for-longer price environment. Furthermore, the Company remains well-placed to consider business development opportunities created as a result of this unfortunate market dynamic, and we continue to aggressively screen compelling opportunities at attractive valuations, in line with our stated growth strategy.

This year represents a critical juncture for the Company as we seek to build on the momentum generated following the merger. We are wholly focused on delivering the objectives that are under our control, namely operational progress in Congo, and in Nigeria (when that deal completes), as well as further new business development in line with our strategy.

The Company is confident that it has the right assets, people and strategy to achieve its ultimate objectives of becoming a leading, independent E&P, focused on Africa. While the near-term outlook is both uncertain and challenging for the entire industry, we believe in the long-term demand for hydrocarbons across the African continent, and believe we are particularly well-placed to capitalise on opportunities that will deliver long-term, sustainable value for our shareholders.

Finally, I'd like to thank the PetroNor E&P team for their tireless work and extend thanks to our wider stakeholders, including partners and host governments. We are excited about the future and look forward to reporting on our progress throughout the year.

Yours Sincerely,

Eyas Alhomouz
Chairman

POSITIONED FOR GROWTH

Knut Søvold | Chief Executive Officer

We believe that we have all the elements required, in terms of management, expertise, strategy, network, assets, and supportive shareholders, to realise our long-term ambitions, and are subsequently uniquely-placed to capitalise on the challenging market dynamics and to benefit from any opportunities that may arise.

"PETRONOR WAS FORMED ON THE BASIS OF CREATING LOCAL GROWTH AND SUSTAINABLE OPERATIONS."

PetroNor Timeline

2020 onward

Develop PNGF Sud, initially through 2020 - 2021 infill drilling programme

Finalise PNGF Bis contract and commence drilling

Rejuvenate OML 113 partnership and Aje development plan

Resolve Senegal and The Gambia disputes

Grow PetroNor into a leading E&P independent through M&A

Target 30,000 boepd net production by 2023

2019

Completed business combination with African Petroleum Corporation and relisted as PetroNor on Oslo Axess

PNGF Sud reaches production of 22,000 bbl/d, up >7,000 bbl/d (~50%) since licence-acquisition

Litanzi infill drilling programme approved

Announced Aje transaction with Panoro – low-cost entry into producing asset with significant unlocked potential. Strengthens the PetroNor shareholder base through share consideration

2017

Entered 2017 with PNGF Sud gross production of circa 15,000 bbl/d

Together with new operator, Perenco, initiated significant operational efforts to reduce costs and increase production

2016

NOR Energy and Petromal joined forces

PetroNor established

Acquired PNGF Sud interest in Congo following Total's exit

Q&A

Q: What's the long-term vison?

A: We want to establish PetroNor E&P as a leading, full-cycle African oil and gas company. We recognise the importance of achieving scale to ensure relevance and open up exciting opportunities, and have set ourselves a target of producing 30,000 boepd net in the next few years, through organic and inorganic growth. Clearly this target is ambitious, and based on market conditions and ability to fund and execute sizeable transactions, however it reflects the scale of our near-term ambitions. The current challenges in the oil market also open opportunities for commercially-robust transactions. We are confident that we have the right people, assets and supportive major shareholders to achieve this vision.

Q: How is the production at PNGF Sud doing?

A: The PNGF Sud has been a great success, with growth from c.15,000 bbl/d to a current production level of c.23,000 bbl/d. This solid production growth of >50% has been achieved through maintenance and simple workovers at a cost of some 2 USD/bbl and shows the proficiency of Perenco as a brown-field operator. In addition to the already identified 2C opportunities, the asset has a significant ~2bn bbl of Stooip and an average recovery factor of 23%, indicating that there is still potential for continued production growth through infill drilling in the years to come.

Q: How will the Company meet the current crisis in the oil industry related to the drop in oil price?

A: In light of the challenging environment the industry is currently experiencing, the immediate priority is efficiency and cost control. We have implemented a significant long-term cost reduction in the company through a restructuring and reduction of salary levels with cuts of 40% for top management. In addition, we are revisiting all expenses and tasks to reduce the general cost level down from USD 14 million in 2019 to USD 9 million for 2020. The Company overhead has been adapted to our current operational size, whilst ensuring the required structure to effectively execute our growth plan. Our plan to relocate from Australia this year is part of the streamlining to minimize overhead cost in the Company.

Q: What is the Company doing in response to ESG trends that have emerged in recent years?

A: The Norwegian part of PetroNor was formed on the basis of creating local growth and sustainable operations some ten years ago, way before ESG became an industry standard. In other words, we have been adhering to the individual elements of ESG for many years but are now communicating these more effectively to meet the expectations of the wider, global investor community. In Congo, PetroNor E&P is engaged in the building of schools. In Nigeria, our first project will target a significant reduction in gas flaring and aim to bring power to Lagos, a city in desperate need of an energy source to replace its current use of diesel generators. The Aje project will therefore reduce the carbon footprint significantly, whilst reducing local pollution.

Q: What is your view on climate change and its impact on your business?

A: Global climate change is a very real problem for everyone, and we recognise our role and responsibility as an energy company and steward of the environment. We believe that hydrocarbons will, and should, continue to play an important role in the global energy mix for decades to come, especially in Africa where circa 600 million people still do not have access to reliable electricity. We want to ensure our activities have a positive socioeconomic impact on the communities and countries in which we work, whilst also recognising the environmental impact of our activities. The management team has strong environmental focus and credentials, and we will always seek to display these through responsible operating activities.

Q: In terms of becoming a full-cycle E&P, what is the desired weighting between exploration, development and production?

A: The focus for the business will be on production as we believe it's important to ensure the business is supported by cash flow. As such we would envisage that weighting to be on production and development where we see near-term production. We will also engage in exploration where this makes commercial sense and the risk to our capital base is limited.

Q: Where is PetroNor E&P currently in its strategic development cycle?

A: We are really at the beginning of that cycle but have begun with a significant head-start in terms of a portfolio that already provides reliable, positive free cash flow and significant upside potential. A core aspect of our strategy is predicated on business development, and our ability to identify and execute on compelling opportunities in line with our strategic objectives. We have already executed one deal in the form of the Aje transaction, and continue to screen a strong pipeline of opportunities. We expect to be presented with an even higher volume of exciting opportunities this year and beyond, on account of the recent pressure exerted on the industry by the rapid commodity price decline.

Q: What do you consider to be the Company's key investment highlights and differentiating factors?

A: We want to build a business underpinned by cash flow and reserves, so are constantly screening opportunities to enhance both of these metrics. Needless to say, our long-term priority is to generate sustainable value for our shareholders, and with the Board and management team representing a material holding in the company, we are wholly aligned with all shareholders in this regard, and consider shareholder value in every decision we take. We believe that the knowledge and expertise of the management team and Board are core assets, especially for a company of our current size. The technical industry-knowledge we possess is extensive, and we intend to leverage this in order to identify compelling opportunities that require our technical lens to realise full potential from these assets. We also possess the requisite commercial track record, and network throughout Africa, our region of geographical focus, to source, assess and execute on transactions in line with our stated strategy.

Q: What are the biggest challenges you see on the near-term horizon?

A: The sector has numerous challenges, and these have been exacerbated by the rapid commodity price decline through early 2020. Access to cost-efficient capital is the primary challenge for our particular growth strategy, however we believe that we have the right experience, strategy and network to be able to circumnavigate these challenges. Doing business in Africa is often cited as an industry challenge, and whilst this can be very true, we believe that our experience of working across the continent holds us in good stead, and we are wholly committed to maintaining the appropriate level of Governance to ensure we will only operate in countries where we believe we can operate transparently, in line with industry best practice.

Q: What are the key considerations for you when it comes to inorganic growth?

A: We must have a laser focus on our strategic objectives and ensure that any opportunities we progress are in line with these goals. We are seeking value accretive opportunities that present us with an opportunity to leverage our deep technical and commercial expertise to extract maximum value. We also need to ensure we have conducted rigorous due diligence on target assets and pay the right price to execute on them. Clearly, we expect a lot of compelling opportunities to present themselves in this distressed market, and we must ensure we are in a position to exploit these. We hold the social and environmental impact of our operations in very high regard and these considerations will always play a major role in our execution of inorganic growth.

Q: What 3 key messages would you like shareholders to take from this Annual Report?

A: We have completed a merger between two companies and have now defined our long-term ambitious strategy; we would ultimately like to be judged on what we can deliver in terms of value creation and operational objectives over the coming years.

The industry is particularly challenging at present, and the Board is taking all appropriate measures to ensure the long-term prosperity and sustainability of our business for the benefit of all our shareholder.

We believe that we have all the elements required in terms of management, expertise, strategy, network, assets, and supportive shareholders to realise our long-term ambitions, and are subsequently uniquely placed to capitalise on the challenging market dynamics and to benefit from a once-in-a generation opportunity in the industry.

Knut Søvold,
Chief Executive Officer

Introduction

PetroNor's classification of reserves and resources complies with the guidelines established by the Oslo Stock Exchange and is based on the definitions set by the Petroleum Resources Management System (PRMS-2007), sponsored by the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE / PRMS) from 2007 and 2011.

Reserves are the volume of hydrocarbons that are expected to be produced from known accumulations:

- On Production
- Approved for Development
- Justified for Development

Reserves are also classified according to the associated risks and probability that the reserves will be produced.

1P – Proved reserves represent volumes that will be recovered with 90% probability
2P – Proved + Probable represent volumes that will be recovered with 50% probability
3P – Proved + Probable + Possible volumes that will be recovered with 10% probability.

Contingent Resources are the volumes of hydrocarbons expected to be produced from known accumulations:

- In planning phase
- Where development is likely
- Where development is unlikely with present basic assumptions
- Under evaluation

Contingent Resources are reported as 1C, 2C, and 3C, reflecting similar probabilities as reserves.

Disclaimer

The information provided in this report reflects reservoir assessments, which in general must be recognized as subjective processes of estimating hydrocarbon volumes that cannot be measured in an exact way.

It should also be recognized that results of recent and future drilling, testing, production, and new technology applications may justify revisions that could be material. Certain assumptions on the future beyond PetroNor's control have been made. These include assumptions made regarding market variations affecting both product prices and investment levels. As a result, actual developments may deviate materially from what is stated in this report.

The estimates in this report are based on third party assessments prepared by AGR Petroleum Services AS in October 2019 for PNGF Sud and PNGF Bis.

PetroNor assets portfolio

PetroNor's assets are located approximately 25km off the coast of Pointe Noire in water depths of 80-100 metres. PetroNor, through Hemla E&P Congo (HEPCO), participated in the 2016 tender process with the Congo Ministry of Petroleum for participation in the PNGF Sud licence (brown field). HEPCO was awarded a 20% working interest in the PNGF Sud licence, corresponding to a net 10.5% to PetroNor. Furthermore, the licence partnership has, through an umbrella agreement, the right to negotiate, in good faith, the licence terms of the adjacent PNGF Bis licence, where Perenco is intended to be the operator. The umbrella agreement assigns a 28% HEPCO share to PNGF Bis, yielding a PetroNor 14.7% interest in PNGF Bis.

During 2019, PetroNor made an acquisition of a nominal 6.5% interest in OML 113 (Aje) in Nigeria from Panoro Energy. An agreement was also made between PetroNor and YFP to jointly further-develop OML 113. These agreements are described in further detail in the Directors' report. This transaction is not yet completed and is not part of this ASR statement.

During 2019, PetroNor completed a merger with African Petroleum Corporation. The merged company currently has exploration assets in Senegal and The Gambia. As these constitute prospective resources, they are not part of this ASR.

PNGF Sud: offshore Congo-Brazzaville, operator Perenco, PetroNor 10.5%.

PNGF Sud is a development and exploitation licence covering an area containing several oil fields, Tchibouela, Tchibouela East, Tchendo, Tchibeli and Litanzi fields. The interest in PNGF Sud is held directly and with a 20% share, by Hemla E&P Conco ("HEPCO"). Through PetroNor's ownership of 52.5% of HEPCO, this constitutes an indirect 10.5% share in the PNGF Sud licence. The licence ownership has been effective since 1.1.2017 with expiry after 20 years plus a 5-year extension period. Since granting of the licence, Perenco with partner support, has been committed to strict HSE compliance while growing production, improving maintenance routines and field integrity in a stepwise and prudent manner.

In October 2019, AGR performed a full Competent Person's Report ("CPR") covering the Reserves (1P, 2P and 3P) and Resources (1C, 2C and 3C) in both PNGF Sud and PNGF Bis. The above figures were evaluated as at 31.12.18.

Gross production during 2019 was 8.0 MMbbl of oil and 0.97 Bcf of gas. This corresponds to an average 21,920 bbl/d and 2.7 mmscfd.

As per the PRMS/SPE guidelines, only the portion of gas contributing to power generation (on Tchibouela only) is included in the overall reserves in the AGR CPR. The gas is being used centrally in the field complex as fuel for power-generating turbines which is subsequently transmitted to the individual field platforms via electrical power cables. For the purpose of this report, the numbers quoted below as MMbbl do not include the oil-equivalent gas but are included in the appendix reserves and resource tables.

This PetroNor ASR uses as its basis the Reserves and Resources from the 2019 October AGR CPR, subtracting only the volumes of oil and gas produced during 2019 to arrive at the Reserves and Resources as per 31.12.19. As the only product sold is oil, PetroNor will in the text below, when referring to Reserves and Resources, mainly refer to oil and term these with the unit MMbbl.

As of 31.12.2018, AGR evaluated that gross 1P Proved Reserves yield 74.90 MMbbl in all the PNGF Sud fields in the Cenomanian and Turonian reservoirs. Gross 2P Proved plus Probable Reserves at PNGF Sud amounted to 110.5 MMbbl in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at PNGF Sud amounted to 141.7 MMbbl.

As of 31.12.2019, by subtracting the 2019 production from the above figures, gross 1P Proved Reserves yield 66.90 MMbbl in all the PNGF Sud fields in the Cenomanian and Turonian reservoirs. Gross 2P Proved plus Probable Reserves at PNGF Sud amounted to 102.5 MMbbl in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at PNGF Sud amounted to 133.7 MMbbl.

Gross 1C Resources yield 23.0 MMbbl in all the PNGF Sud fields in the Cenomanian and Turonian reservoirs. Gross 2C Resources at PNGF Sud amounted to 29.2 MMbbl in the same reservoirs. Gross 3C Resources at PNGF Sud amounted to 51.8 MMbbl.

These evaluations yield 1P Proved Reserves net to PetroNor of 7.02 MMbbl, 2P Proved plus Probable Reserves net to PetroNor of 10.76 MMbbl and 3P Proved plus Probable plus Possible Reserves net to PetroNor of 14.04 MMbbl.

Additional potentially recoverable resources net to PetroNor are approximately 2.4 MMbbl 1C, 3.1 MMbbl 2C and 5.4 MMbbl 3C.

These Reserves and Contingent Resources are PetroNor's net volumes before deductions for royalties and other taxes, reflecting the production and cost-sharing agreements that govern the assets.

PNGF Bis: offshore Congo-Brazzaville, operator Perenco, PetroNor 14.7%.

The PNGF Bis licence neighbours the PNGF Sud licence and contains two discoveries, Louissima and Loussima SW. The two discoveries are proven by three wells including DST's drilled from 1985 to 1991. The primary potential is identified in the pre-salt Vanji formation with promising DST rates, but the exploration and appraisal wells also include an oil column in the post-salt Senji fm (not tested). A long-term test production period, with a rented jack-up with a purchase option and an 11 km pipeline tie-back to one of the existing Tchibouela wellhead platforms, is a likely scenario. This allows cost recovery of the investments during the test production and allows upscaling of production levels with additional producers as resources are matured to reserves.

Net to PetroNor 1C Contingent Resources yield 3.29 MMbbl in the Loussima SW Vanji and Senji fm. Net 2C at PNGF Bis Loussima SW amounts to 4.25 MMbbl in the same reservoirs. Net 3C amounts to 5.26 MMbbl.

Management discussion and analysis

PetroNor uses the services of AGR Petroleum Services for 3rd party verifications of its reserves and resources.

All evaluations are based on standard industry practice and methodology for production of decline analysis and reservoir modelling, based on geological and geophysical analysis. The following discussions are a comparison of the volumes reported in previous reports, along with a discussion of the consequences for the year-end 2019 ASR.

PNGF Sud: During the years 2017, 2018 and 2019, production levels have grown from the initial c. 15,000 bbl/d when Perenco and partners took over. This has materialised through revitalising existing producers via replacements or upsizing of Electrical Submersible Pumps (ESP's), acidizing, clean up or reperforating of wells or converting from the Cenomanian to the Turonian (less depleted) formations. Significant surface debottlenecking is also taking place, with projects ranging from improved power generation, gas-lift compressor upgrades, pump replacements and other surface process improvements. Production from Tchibeli has been routed to Tchendo by installing a new pipeline to avoid third party processing tariffs previously paid to the Nkossa FPSO. These brick-by-brick improvements have yielded a production level during 2019 of 21,920 bbl/d. The production improvements alone have yielded more than a 100% reserves replacement each year, at a cost of less than 2 USD/bbl. In addition to this, significant infill drilling potential has been identified in all fields. Resources identified as infill potential are classified as Contingent resources as these are most likely not decided upon until the workover potential has been exhausted.

An infill drilling programme was decided for the Litanzi field in 2019 and consequently the 2C resources in this field have been converted to 2P reserves. An infill drilling programme for Tchendo has also been approved starting investments as part of the 2020 budget, but the resources were not included as reserves at time of the CPR and are still listed as 2C resources. Development of 3D static and dynamic models has been and will continue to form the basis of further infill drilling programmes on PNGF.

PNGF Bis: Once investment decisions are made on the Loussima SW project these reserves may become reserves approved for development. A thorough mapping of the Stooip in Loussima SW has been performed by the operator in 2018. This work has been verified by AGR in the mentioned 2018 October CPR and carried on in the 2019 CPR.

Given a successful Loussima SW, a similar development potential is likely for the Loussima Discovery.

Assumptions

The commerciality and economic tests for the PNGF Sud and Bis reserves volumes were based on an oil and condensate price of 60 USD/bbl, although the reserves and resources are not very sensitive to this parameter as OPEX levels are at 12.5 USD/bbl.

2019 – 2P Reserves	(MMbbl)
Balance (gross AGR, PNGF Sud – Dec 31, 2018)	110.50
Production 2019, PNGF Sud	(8.00)
Balance 31.12.2019 – 2P gross, PNGF Sud	102.50
Balance 31.12.2019 – 2P net, PNGF Sud	10.76

2P and 2C Reserves and Resources Status	(MMbbl)
Balance 31.12.2019 – 2P/2C gross, PNGF Sud	131.70
Balance 31.12.2019 – 2P/2C net, PNGF Sud	13.83
Balance 31.12.2019 – 2P/2C gross, Sud+Bis	160.60
Balance 31.12.2019 – 2P/2C net, Sud+Bis	18.08

PetroNor's total 1P reserves at end of 2019 amount to 7.02 MMbbl. PetroNor's 2P reserves amount to 10.76 MMbbl and PetroNor's 3P reserves amount to 14.04 MMbbl. This reflects the October 2019 reserve report for the PNGF Sud field, conducted by AGR Petroleum Services AS and production since the field start-up.

PetroNor's Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By the end of 2019, PetroNor's assets contain a total 2C volume of approximately 7.3 MMbbl.

Knut Søvold
Chief Executive Officer
6 May 2020

Reserves and resources as per 31.12.19 (AGR CPR as at 31.12.18 dated 31.10.2019 and corrected for 2019 production)

	Gross Reserves (developed or under development)									Gross Contingent Resources (undeveloped)								
	1P			**2P**			3P			1C			**2C**			3C		
	Oil mmbo	Gas bcf	Boe mmboe	**Oil mmbo**	**Gas bcf**	**Boe mmboe**	Oil mmbo	Gas bcf	Boe mmboe	Oil mmbo	Gas bcf	Boe mmboe	**Oil mmbo**	**Gas bcf**	**Boe mmboe**	Oil mmbo	Gas bcf	Boe mmboe
PNGF Sud																		
Tchibouela	37.91	6.43	39.05	**56.61**	**10.83**	**58.53**	73.81	19.43	77.27	6.10	3.50	6.72	**8.80**	**5.00**	**9.69**	17.10	9.80	18.85
Tchendo	10.56	–	10.56	**18.96**	**–**	**18.96**	24.06	–	24.06	8.90	–	8.90	**10.70**	**–**	**10.70**	19.60	–	19.60
Tchibeli	8.13	–	8.13	**14.13**	**–**	**14.13**	18.43	–	18.43	8.00	–	8.00	**9.70**	**–**	**9.70**	15.10	–	15.10
Litanzi	10.30	–	10.30	**12.80**	**–**	**12.80**	17.40	–	17.40	–	–	–	**–**	**–**	**–**	–	–	–
Total	66.90	6.43	68.04	**102.50**	**10.83**	**104.43**	133.70	19.43	137.16	23.00	3.50	23.62	**29.20**	**5.00**	**30.09**	51.80	9.80	53.55
PNGF Bis																		
Loussima (Bis)	–	–	–	**–**	**–**	**–**	–	–	–	22.40	–	22.40	**28.90**	**–**	**28.90**	35.80	–	35.80
Total	66.90	6.43	68.04	**102.50**	**10.83**	**104.43**	133.70	19.43	137.16	45.40	3.50	46.02	**58.10**	**5.00**	**58.99**	87.60	9.80	89.35

Net to PetroNor – Reserves and resources as per 31.12.19 (AGR CPR as at 31.12.18 dated 31.10.2019 and corrected for 2019 production)

	Net PetroNor Reserves (developed or under development)									Net PetroNor Contingent Resources (undeveloped)								
	1P			**2P**			3P			1C			**2C**			3C		
	Oil mmbo	Gas bcf	Boe mmboe	**Oil mmbo**	**Gas bcf**	**Boe mmboe**	Oil mmbo	Gas bcf	Boe mmboe	Oil mmbo	Gas bcf	Boe mmboe	**Oil mmbo**	**Gas bcf**	**Boe mmboe**	Oil mmbo	Gas bcf	Boe mmboe
PNGF Sud 10.50%																		
Tchibouela	3.98	0.67	4.10	**5.94**	**1.14**	**6.15**	7.75	2.04	8.11	0.64	0.37	0.71	**0.92**	**0.53**	**1.02**	1.80	1.03	1.98
Tchendo	1.11	–	1.11	**1.99**	**–**	**1.99**	2.53	–	2.53	0.93	–	0.93	**1.12**	**–**	**1.12**	2.06	–	2.06
Tchibeli	0.85	–	0.85	**1.48**	**–**	**1.48**	1.94	–	1.94	0.84	–	0.84	**1.02**	**–**	**1.02**	1.59	–	1.59
Litanzi	1.08	–	1.08	**1.34**	**–**	**1.34**	1.83	–	1.83	–	–	–	**–**	**–**	**–**	–	–	–
Total	7.02	0.67	7.14	**10.76**	**1.14**	**10.96**	14.04	2.04	14.40	2.42	0.37	2.48	**3.07**	**0.53**	**3.16**	5.44	1.03	5.62
PNGF Bis 14.70%																		
Loussima (Bis)	–	–	–	**–**	**–**	**–**	–	–	–	3.29	–	3.29	**4.25**	**–**	**4.25**	5.26	–	5.26
Total	7.02	0.67	7.14	**10.76**	**1.14**	**10.96**	14.04	2.04	14.40	5.71	0.37	5.77	**7.31**	**0.53**	**7.41**	10.70	1.03	10.88

Oil equivalents	5.615 mscf/boe
2P Incr. from '19	26% (incl. 2019 produced volumes -8.0 MMbbl)
2C Incr. from '19	-9% (PNGF Sud only)
2C Incr. from '19	-4% (PNGF Sud and PNGF Bis)

OUR ESG COMMITMENT

PetroNor E&P is committed to operating responsibly and we endeavour to enrich the communities where we operate.

To ensure PetroNor E&P's efforts are sustainable, corporate social investments are primarily focused on project work in the following key areas:

Environmental

- We strive to minimise any adverse impact on the environment
- We always undertake Environmental Social Impact Assessments (ESIA) prior to all major activities & communicate results
- to stakeholders
- In Nigeria, our plans for the Aje project have a positive impact through the elimination of existing gas flaring (equivalent to removing the CO_2 produced by 55,000 cars)
- Gas development will also lead to displacement of gasoline used for power generation in Lagos

Social

- Our commitment to operating responsibly is evidenced by a history of social projects undertaken by the leadership
- The Power to Educate initiative is focused on improving conditions for families in areas with no access to electricity
- Other projects include human capacity development and access to quality health care
- In Congo-Brazzaville, 5% of net profits are invested in local community education initiatives

Governance

- We adhere to best practice corporate governance standards
- Our business development model includes increased access to opportunities through the formation of subsidiary companies with local partners
- This indirect ownership is supported by careful selection of local leadership and strong representation on subsidiary boards to ensure high-quality governance
- Use contemplated re-domiciliation to improve the diversity of the Board of Directors.

Case study

Power to Educate

Power to Educate is an initiative supporting education in emerging countries. Its platform is designed for companies in the oil and gas industry to help increase the number of children that receive an education.

According to the World Health Organisation (WHO), household pollution in Africa and Asia is responsible for 4.3 million deaths each year due to the use of firewood indoors. The programme and platform aim at substituting firewood with LPG, Solar and Wind solutions for domestic power usage. With no need to collect firewood, children can utilise the time to go to school.

The platform tracks the increased energy usage of LPG, Solar and Wind and measures this locally as a reduction in use of firewood. Power to Educate then awards the local communities with funds dedicated to educational programmes for each increased use of Solar, Wind and LPG.

For more: www.powertoeducate.com

Eyas Alhomouz | Non-Executive Director and Chairman

Qualifications:

Mr. Alhomouz graduated from Brigham Young University in Provo, Utah with a degree in Chemical Engineering and from the Colorado School of Mines, in Golden, Colorado with a master's degree in Mineral and Energy Economics.

Experience:

Mr. Alhomouz has strong experience from the oil and gas sector covering the United States, North Africa, and the GCC. He began his career with Schlumberger Oilfield Service as a wireline engineer in Midland, Texas. From there he went on to work for Cromwell Energy in Denver, Colorado, in the role of international business development manager. Then, as chief operating officer and finance director of Prism Seismic, he oversaw the growth of the Colorado based consulting and oil and gas software development firm, and later the acquisition of the company by Sigma Cubed where, post-acquisition of Prism Seismic, he went on to serve as a director of business development, Middle East. Mr. Alhomouz's career then took him to Qatar as general manager of Jaidah Energy, an Omani-Qatari owned company servicing the oil and gas sector in Qatar.

Knut Søvold | Executive Director and Chief Executive Officer

Qualifications:

Mr. Søvold holds a MSc in Petroleum from The Institute of Technology in Trondheim (NTH), Norway.

Experience:

Mr. Søvold has 30 years of experience in the oil and gas industry, at both executive management and technical levels. His extensive experience covers fields and licenses in the North Sea, North and West Africa, Middle East, Far East and FSU, as well as management and administration through establishing and operating companies in Norway, United Kingdom, Kazakhstan and West Africa. Mr. Søvold was in the management team of the Snorre Field in the North Sea, with a production of 200,000 bbl/d. Mr. Søvold has been working with West African assets since 2000 and in Nigeria since 2008. Furthermore, he has also been working with gas to LNG, including novel solutions such as FLNG, gas to power, as well as LNG-regasification.

Jens Pace | Non-Executive Director

Qualifications:

Mr. Pace holds a BSc in Geology and Oceanography from the University of Wales and a MSc in Geophysics from Imperial College, London.

Experience:

Mr. Pace has a background in geosciences, and has had a career spanning over 30 years at BP Exploration Operating Company Limited ("BP"), and its heritage company Amoco (UK) Exploration Company. Mr. Pace has held senior positions at BP for over 10 years, gaining exploration and production experience in Africa, namely: Algeria, Angola, Congo, Gabon and Libya. In addition, he has experience in Europe, Russia and Trinidad. He has contributed to a number of BP's exploration discoveries over his career. Most recently, Mr. Pace managed a large and active exploration portfolio for BP in North Africa. In addition to exploration activities, Mr. Pace has gained experience in the areas of field development and as a commercial manager.

Mr. Pace joined African Petroleum Corporation Ltd as Chief Operating Officer in October 2012; and was appointed Chief Executive Officer by the Board in November 2015. Following the merger with PetroNor E&P Ltd, Mr. Pace resigned as Chief Executive Officer on 29 February 2020.

Roger Steinepreis | Non-Executive Director

Qualifications:
Mr. Steinepreis holds a Bachelor of Jurisprudence and Bachelor of Laws (1985) from the University of Western Australia.

Experience:
Mr. Steinepreis is a corporate and resources lawyer with over 30 years' experience. He has acted as the legal adviser on in excess of 40 initial public offers and has advised numerous companies, large and small, on strategic acquisitions, whether by takeover, scheme of arrangement, trade sale or other means. Mr. Steinepreis serves as the executive chairman of Steinepreis Paganin, one of the largest, specialist corporate law firms in Perth, Australia, and serves on other boards.

Joseph Iskander | Non-Executive Director

Qualifications:
Mr. Iskander holds a Degree in Accounting and Finance with high distinction from Helwan University, Egypt.

Experience:
Mr. Iskander brings over 20 years of experience in the financial services industry, covering asset management, private equity, portfolio management, financial restructuring, research, banking, and audit. He began his career at Deloitte & Touche (Egypt) as an Auditor. Mr. Iskander served as non-executive director on the boards of EFG Hermes in Egypt, Oasis Capital Bank in Bahrain, Sun Hung Kai & Co. in Hong Kong, Qalaa Holdings in Egypt, Emirates Retakaful in UAE, Marfin Laiki Bank in Cyprus and Marfin Investment Group in Greece. Mr. Iskander headed the research team at Egypt's Prime Investments and was earlier an investment advisor at Commercial International Bank (CIB). He then went on and joined Dubai Group as an investment manager in 2004 and has worked on a range of M&A transactions, advisory services, asset management, and private equity transactions with a collective value in excess of USD 8 billion. Mr. Iskander was managing director of Asset Management at Dubai Group and the former head of research at Dubai Capital Group until 2009. He joined Emirates International Investment Company in July of 2017 as the director of private equity spearheading and managing EIIC's investments.

Alexander Neuling | Non-Executive Director

Qualifications:
Mr. Neuling holds a BSc (Hons) in Chemistry from Leeds University, United Kingdom and he is a Fellow of the Institute of Chartered Secretaries and Administrators and a Fellow of the Institute of Chartered Accountants of England & Wales.

Experience:
Mr. Neuling is a chartered accountant and has been advising within extractive industries for more than 15 years. Mr. Neuling has held numerous senior management positions at listed companies, and previously worked for Deloitte in London and Perth.

Your Directors present their report on PetroNor E&P Limited ("PetroNor" or the "Company") for the year ended 31 December 2019.

Directors

The names of Directors in office during the financial year and until the date of this report are as follows. Directors were in office for this entire period unless otherwise stated.

E Alhomouz	Non-Executive Chairman, appointed 30 August 2019
K Søvold	Executive Director, appointed 30 August 2019 Chief Executive Officer, appointed 29 February 2020
J Pace	Executive Director and Chief Executive Officer, resigned 29 February 2020 Non-Executive Director, appointed 29 February 2020
S West	Executive Director and Chief Financial Officer, resigned 29 February 2020
J Iskander	Non-Executive Director, appointed 30 August 2019
A Neuling	Non-Executive Director, appointed 6 April 2020
R Steinepreis	Non-Executive Director, appointed 6 April 2020
D King	Non-Executive Director, resigned 1 February 2020
B Moe	Non-Executive Director, resigned 18 October 2019
T Turner	Non-Executive Director, resigned 8 February 2020

The names of Directors for the Cypriot Company, PetroNor E&P Ltd, during the financial year and until the merger with the Company on 30 August 2019 are as follows:

E Alhomouz	Director
K Søvold	Director
G Ludvigsen	Director
H Marshad	Director, appointed 26 February 2019
A Georghiou	Director, appointed 17 April 2019
N Kouyialis	Director, appointed 17 April 2019

Company Secretary

Ms. Angeline Hicks

Principal activity

The Company's principal activity during the year was oil and gas exploration and production.

Review of operations

Corporate

PetroNor E&P and African Petroleum Merger

On 19 March 2019, the Company (previously called African Petroleum Corporation Limited) entered into a combination agreement with Cypriot company PetroNor E&P Ltd and its shareholders NOR Energy AS ("NOR") and Petromal – Sole Proprietorship LLC ("Petromal").

The transaction completed on 30 August 2019, with 816,198,842 new shares in the Company issued to NOR and Petromal as consideration to acquire 100% of the shares in the Cypriot company. The consideration for the transaction also included 155,466,446 warrants with a nil exercise price and were subject to vesting conditions dependent on a) a signed acquisition / farm-in agreement for a gas asset in Nigeria, and b) a signed gas offtake agreement relating to the gas from the asset. All the warrants expired on 31 December 2019, as the vesting conditions had not occurred.

The transaction transformed the Company into a full-cycle E&P company.

The transaction was considered a reverse acquisition, and consequently the Annual Report and Financial Statements are prepared as a continuance of the operations of the Cypriot company. Additional details on the accounting policies are provided in Note 3.

Operational updates

Republic of Congo – PNGF Sud

PNGF Sud fields are located approximately 25 km off the coast of Pointe-Noire in water depths of 80 to 100 metres. PNGF Sud comprises 3 operating licenses, Tchibouela II, Tchendo II and Tchibeli-Litanzi II, covering five oil fields: Tchibouela Main, Tchibouela East, Tchendo, Tchibeli and Litanzi.

PetroNor, through Hemla E&P Congo, participated in the 2016 tender process with the Congo Ministry of Hydrocarbon for participation in the PNGF Sud licence. As of 1 January 2017, Hemla E&P Congo was awarded a 20% working interest in the PNGF Sud licenses (net 10.5% to PetroNor).

Initially discovered in 1979, PNGF Sud commenced production in 1987 and produces from 61 wells in five oil fields, Tchibouela, Tchibouela East, Tchendo, Tchibeli and Litanzi.

Following the entry of the new licence group in 2017, significant operational improvements have been made, increasing gross production from c. 15,000 bbl/d in January 2017. The average production in 2019 was 21,920 bbl/d. Through further workovers, surface and process improvements and infill drilling, gross production from PNGF Sud is expected to continue to grow in the coming years.

The PNGF Sud fields are developed with seven wellhead platforms and currently produce from more than 60 active production wells, with oil exported via the onshore Djeno terminal (Tchibouela, Tchendo and Tchibeli) and the Nkossa FPSO (Litanzi). With its long production history, substantial well-count and extensive infrastructure, PNGF Sud offers well-diversified and low-risk production and reserves with low break-even costs.

In October 2019, AGR Petroleum prepared a Competent Person's Report and the reserves below are calculated to 31.12.2019 by subtraction of the production between the cut-off date of the CPR report and year-end 2019.

PetroNor´s Reserves at 31.12.2019

- 1P reserves of 7.02 MMbbl
- 2P reserves of 10.76 MMbbl
- 3P reserves of 14.04 MMbbl

PetroNor's Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By the end of 2019, PetroNor's assets contained a total 2C volume of approximately 7.3 MMbbl.

During 2019, the gross production was 8.0 MMbbl of oil and 0.97 Bcf of gas, resulting in a net to PetroNor of 2.4 MMbbl.

Republic of Congo – PNGF Bis

PNGF Bis is located to the North-West of PNGF Sud and comprises 2 discoveries: Loussima SW and Loussima.

Through an umbrella agreement, the licence partners of PNGF Sud have the right to negotiate, in good faith, the licence terms to enter into a PSC for PNGF Bis. Subject to successful completion of negotiations, PetroNor is expected to hold a 14.7% indirect interest.

Three exploration wells have been drilled on the licence area. A discovery in pre-salt Vandji Fm was made in well LUSM-1 on Loussima in 1985. Loussima SW was discovered by well LUSOM-1 in 1987 with oil in Vandji Fm.

A second well, SUEM-2, was drilled on Loussima SW in 1991 to appraise the Vandji discovery. Hydrocarbon shows were detected in one of the wells in the Albian post-salt Sendji Fm, (analogue to Tchibeli / Litanzi reservoirs in PNGF Sud). The Sendji interval was not production-tested. The depth to the Vandji reservoir is 3,250 mTVDSS, to Sendji around 1,940 mVDSS and the water depth in the area is 110 m. Tests on the Loussima SW LUSOM-1 well produced 4,700 bbl/d and the SUEM-2 well yielded 1,150 bbl/d.

The CPR report prepared by AGR estimates that PNGF Bis holds gross 2C resources of 28.9 MMbbl.

Senegal – ROP & SOSP

The Company's subsidiary African Petroleum Senegal Limited registered a request for arbitration proceedings with ICSID on 11 July 2018 (ICSID case ARB/18/24) to protect its interests in the Senegal Offshore Sud Profond ("SOSP") and Rufisque Offshore Profond ("ROP") blocks in Senegal.

During the year, the matter followed procedural timeframes, with the Company filing a memorial on the merits on 19 July 2019, and the Senegalese Government filed a counter-memorial on the merits of the case on 9 December 2019.

The Company remains open to engaging in constructive dialogue with the Senegalese authorities through appropriate and official channels, with a view to establishing a satisfactory solution that is in the interests of all parties.

Independent petroleum consultant ERC Equipoise prepared an assessment of prospective oil resources attributable to the Company's Senegal Licences and estimates the net unrisked mean prospective oil resources at 1,779 MMbbl.

The Gambia – A1 & A4

The Company's subsidiary African Petroleum Gambia Limited initiated arbitration proceedings at the International Centre for the Settlement of Investment Disputes ("ICSID") which were registered on 17 October 2017 to protect its interests in the A1 and A4 licences in The Gambia (ICSID case ARB/17/38).

During the year, the matter also followed procedural timeframes, with the Company filing a memorial on the admissibility, jurisdiction and the merits on 28 February 2019, and the Gambian Government filed a counter-memorial on the admissibility, jurisdiction and the merits of the case on 12 July 2019.

Post year-end, on 10 January 2020 the Company filed a reply, and in turn the Gambian Government filed a rejoinder on 24 March 2020.

The Company remains open to engaging in constructive dialogue with the Gambian authorities, with a view to establishing a satisfactory solution that is in the interests of all parties.

Independent petroleum consultant ERC Equipoise prepared an assessment of prospective oil resources attributable to the Company's Gambian licences and estimates the net unrisked mean prospective oil resources at 3,079 MMbbl.

Nigeria – OML 113 The AJE Field

PetroNor entered into an agreement with Panoro Energy and Yinka Folawiyo Petroleum (“YFP”) to acquire Panoro’s interest in the OML 113 and the Aje field in Nigeria in October 2019. PetroNor and YFP have formed a joint company, Aje Petroleum, to focus on the revitalisation and further development of OML 113. The ownership of Aje Petroleum is to be shared between YFP and PetroNor on the basis of a 55% and 45% shareholding respectively.

Following completion, Aje Petroleum will hold a 75.5% participating interest and an average economic interest in the order of 38.7% in OML 113, with an initial 29% economic interest at the onset of the transaction. Additional details on licence interests are provided in the attached appendix.

YFP, as the operator of OML 113, will engage Aje Petroleum as a technical service company.

The completion of the YFP Agreement is subject to authorisation of the Nigerian Department of Petroleum Resources and consent of the Minister of Petroleum Resources.

The Aje Field will be redeveloped through drilling of additional gas and oil wells by extraction of liquid condensate offshore before an eventual tie-back of gas to shore. Significant additional contingent resources exist in the Aje field. Above the Turonian oil rim, from which circa half of today’s production is produced, is a significant undeveloped gas-condensate discovery. Additional contingent resources have been identified in both the Turonian oil rim and the underlying Cenomanian sands from which the other half of today’s production is extracted.

A staged development is planned to exploit the contingent resources in a manner which reduces development risk. The initial phase constitutes drilling of gas injection and production wells to allow offshore extraction of condensate. This is estimated to more than double today’s liquid production in addition to removing the current gas flaring in the field today. The secondary objective of the gas wells is to appraise for the best location of additional oil well(s) in the Turonian or Cenomanian. This condensate stripping may be regarded a stand-alone development, and can continue until a development decision on phase 2, involving a gas pipeline to shore for export to power, or even construction of a gas plant for removing additional liquid components before selling the dry gas to power.

The Aje field has a current gross production of circa 2,300 bbl/d with remaining reserves of 2.3 MMbbl. This corresponds to 301 bbl/d production and 0.3 MMbbl net to PetroNor at a current economic interest of 13.1%. The above development plan entails a gross 2C resource of circa 110 MMbbl (gas and condensate). With an economic interest after development of 17.4%, this corresponds to some 19 MMbbl net to PetroNor.

Result

The Board of Directors (the “Board”) confirms that the annual financial statements have been prepared pursuant to the going concern assumption. The continuing impact that Covid-19 will have on the Group’s operations and the global markets, plus the uncertainty on the Group’s ability to renegotiate outstanding payables to significant shareholders, indicate material uncertainties on the status of going concern. The going concern assumption is based upon the financial position of the Group and the development plans currently in place. In the Board of Directors’ view, the annual financial statements give a true and fair view of the Group’s assets and liabilities, financial position and results. PetroNor E&P Limited is the parent company of the PetroNor Group (the “Group”). Its financial statements have been prepared on the assumption that PetroNor will continue as a going concern.

The Group had USD 27.9 million in cash and bank balances as of 31 December 2019 (2018: USD 7.9 million).

PetroNor E&P Limited prepares its financial statements in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board. The financial report also complies with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

The consolidated financial statements are presented in US dollars.

Financial performance and activities

The Group reported an EBITDA of USD 49 million for the year ended December 31, 2019, compared to USD 53.10 million in the same period in 2018. Net loss attributable to the equity holders of the parent was USD 13.36 million for 2019, compared to net profit of USD 7.84 million in 2018. The decrease in profit is predominantly due to the recognition of a share-based payment expense of USD 19.4 million in the current year for the reverse acquisition transaction. Additional details providing the recognition rationale and subsequent disclosure are in Note 23a of the financial statements.

Oil and gas revenue in the year was (net of royalties and taxes) USD 57.5 million arising from sale of 0.88 million barrels of crude oil at an average price of 65.25 USD per barrel. The revenue increased by 5.1% as compared to last year. There is an 8.5% increase in the oil production and a 3.4% decrease in the price, as compared to 2018.

EBITDA margin of 47.7% is slightly lower as compared to last year’s 52.5%, mainly because of the business development and legal and professional expenses incurred during 2019. The operational efficiency of the asset in Congo has improved.

Intangible non-current assets of USD 4.7 million, represent the previous tender costs, entry bonus and signature bonus paid in 2017 to acquire the share in PNGF Sud.

The production assets and equipment balance of USD 22.6 million, included additional CAPEX investment of USD 12.3 million in the PNGF Sud licence during the year.

Allocation of profits and losses

Funding

During the year, the Company renegotiated the terms and extended the credit of a short-term debt facility of USD 12.9 million from Rasmala (London and Dubai based investor group). The loan was replaced in May 2020 with a USD 15 million facility with 12 months' grace period and final maturity date in October 2022.

Dividends paid or recommended

During the year no dividend was paid or recommended. However, part of the consideration for the merger, stipulated a USD 11.5 million cash element to represent the net share distribution of profits from 2018 generated by the operating subsidiary Hemla E&P Congo SA. This cash element of the merger consideration has been classified as a dividend that was approved on the date of the merger. As at 31 December 2019, only USD 1.1 million of the cash consideration had been paid, with the USD 10.4 million outstanding and included as part of the balance payable to related parties.

Risk factors

Operational risk factors

The development of oil and gas fields in which the Company is involved is associated with technical risk, alignment in consortiums with regards to development plans, and on obtaining necessary licences and approvals from the authorities. Disruptions of operations might lead to cost overruns and production shortfall, or delays compared to the schedules laid out by the operator of the fields. Post year-end, COVID-19-linked restrictions on social mobility imposed by worldwide governments may generate workforce shortages, with disruptions expected for maintenance, inspection, repair and replacement of equipment and drilling activities. As a non-operator for the Congo licences, the Group has limited influence on operational risks related to exploration and development of the licences and fields in which it has interests.

The PNGF Sud licences have been developed since 1987 and thus significant caution has to be taken by the operator to ensure that the old facilities are properly maintained.

The development of the oil fields, in which the Group has an ownership, is associated with significant technical risk and uncertainty with regards to the timing of additional production from new development activities. The PNGF Bis licence is still under negotiations and the contractor group may not reach an agreement with the government.

The Group's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with third parties will be dependent upon developing and maintaining close working relationships with industry partners, joint operators and authorities, as well as its ability to select and evaluate suitable properties, and complete transactions in a highly competitive environment.

Business risk factors

The Group's revenues, cash flow, reserve estimates, profitability and rate of growth depend substantially on prevailing prices of oil and gas, which may fluctuate significantly based on factors beyond the Group's control. Post year-end, the dramatic decline in the oil price demonstrates the volatility in the market, and the difficulty to accurately predict future oil and gas price movements.

Sustained lower oil and gas prices may lead to a material decrease in the Group's net production revenues and may also cause the Group to make substantial downward adjustments to its oil and gas reserves. If oil and gas prices remain depressed over time, it could also reduce the Group's ability to raise new debt or equity financing or to refinance any outstanding loans on terms satisfactory, or at all.

Financial risk factors

The overall risk management programme seeks to minimize the potential adverse effects of unpredictable fluctuations in financial markets on financial performance, ie, risks associated with currency exposures, and debt-servicing. Financial instruments such as derivatives, forward contracts and currency swaps are continuously being evaluated for the hedging of such risk exposures.

Due to the international nature of its operations, the Group is exposed to risk arising from currency exposure, primarily with respect to the Norwegian Kroner (NOK) and the Great British Pound (GBP).

The Group currently has a debt facility with Rasmala and as part of the group strategy to target new projects, it will need to raise further capital. Should additional funding be required in the future for additional capital expenditure for new development phases or working capital requirements, the Group has various alternatives available which it can explore to fulfil such additional requirements. The options include, amongst others, ordinary debt financing, Nordic Bonds, reserves-based lending, project financing, off-take prepayment structures, and the issuance of shares.

Corporate Governance

The main objective for PetroNor's corporate governance is to develop a strong, sustainable, competitive and successful E&P group acting in the best interest of all the stakeholders, within the laws and regulations of the countries where it operates. The Board and management aim for a controlled and profitable development and long-term creation of growth through well-founded governance principles and risk management.

Given its Australian domicile and former NSX listing, the Company's corporate governance framework has been constructed in recognition of, and with regard to, the Australian Corporations Act; the ASX Corporate Governance Council's ("CGC") 'Principles of Good Corporate Governance and Best Practice Recommendations' (Recommendations) and CGC published guidelines; and an extensive range of varying legal, regulatory and governance requirements applicable to publicly-listed companies in Australia. The Board of Directors supports the principles of effective corporate governance and is committed to adopting high standards of performance and accountability, commensurate with the size of the Company and its available resources. Accordingly, the Board of Directors has adopted corporate governance principles and practices designed to promote responsible management and conduct of the Company's business. The current corporate governance plan adopted by the Company is available on the Company's website at www.PetroNorep.com. The Company is in compliance with the NSX Corporate Governance Principles. With the listing on Oslo Axess, the Board acknowledges the Norwegian Code of Practice for Corporate Governance and the principle of "comply or explain". The Group has implemented a policy for Ethical Code of Conduct and works diligently to comply with these guidelines.

Discrimination and equal employment opportunities

PetroNor is an equal opportunity employer, with an equality concept integrated in its human resources' policies. A diversified working environment is embraced, and the Group's personnel policies promote equal opportunities and rights and prevent discrimination based on gender, ethnicity, colour, language, religion or belief. All employees are governed by PetroNor's Code of Conduct, to ensure uniformity in behaviour across a workforce representing a multitude of nationalities.

PetroNor is a knowledge-based group in which a majority of the workforce has earned college or university level educations; or has obtained industry-recognised skills and qualifications specific to their job requirements. Employees are remunerated exclusively based upon skill level, performance and position.

Proportion of local West African employees:

	Actual	Objective
Organisation as a whole	50%	50%
Board	Nil	+20%

Proportion of women:

	Actual	Objective
Organisation as a whole	29%	+20%
Executive management team	Nil	+20%
Board	Nil	40%

Share capital

The Company's share capital consists entirely of 971,665,288 ordinary shares. Over 98.08% of the Company's ordinary shares are admitted for trading on the Oslo Axess (Norway). During the year 816,198,842 shares were issued as part of the consideration to purchase the entire share capital of PetroNor E&P Ltd, a company registered in Cyprus.

Cypriot Company, PetroNor E&P Ltd has 100,000 ordinary shares of nominal value EUR1 (USD 1.20) each.

Rights and obligations of shareholders

In accordance with section 5-8a of the Norwegian Securities Trading Act, the Company provides the following information:

a. there are no restrictions on the transfer of securities;
b. no holders of any securities have special control rights;
c. the Company does not operate an employee share scheme;
d. there are no restrictions on voting rights;
e. there are no agreements between shareholders which are known to the Company and which may result in restrictions on the transfer of securities and/or voting rights within the meaning of Directive 2001/34/EC;
f. the Company's Constitution provides that the Board of Directors shall have no fewer than 3 Directors and no more than 12 Directors. The Directors are elected by a general meeting of shareholders by ordinary resolution. Additionally, pursuant to Clause 13.4 of the Constitution, the Board of Directors may at any time appoint a person to be a Director, provided that the maximum number of Directors is not exceeded. Any such Director appointed will hold office until the next general meeting and will be eligible for reelection. At the Company's Annual General Meeting, one-third of the Directors for the time being, shall retire from office, provided always that no Director except a Managing Director shall hold office for a period in excess of three years without submitting him or herself for reelection. The Directors to retire at an Annual General Meeting are those who have been longest in office since their last election. A retiring Director is eligible for reelection. In the event of equal voting at a Directors' meeting, the Chairman of the meeting shall have a second or casting vote providing there is more than two directors competent to vote on the question. As the Company is incorporated in Australia, the Australian Corporations Act requires the Company to have at least two Directors that reside in Australia.
g. the Company may modify or repeal its constitution or a provision of its constitution by special resolution of shareholders;
h. pursuant to section 198A of the Australian Corporations Act,

the business of a company is managed by or under the direction of the Board of Directors. Pursuant to Clause 2.2 of the Company's Constitution, the Board of Directors has the power to issue shares;

i. subject to the requirements in the Australian Corporations Act, the Company may purchase its own shares in accordance with the buy-back provisions of the Australian Corporations Act, on such terms and at such times as may be determined by the Directors from time to time and approved by the shareholders as required pursuant to the Australian Corporations Act. The Company is not entitled to hold its own shares, subject to exceptions set out in Section 259A of the Australian Corporations Act. Any shares repurchased by the Company will need to be cancelled;

j. there are no significant agreements to which the Company is a party and which take effect, alter or terminate upon a change of control of the Company following a takeover bid;

k. there are no agreements between the Company and its Board members or employees providing for compensation if they resign or are made redundant without valid reason or if their employment ceases because of a takeover bid.

As at 16 April 2020, the Company had 3,067 shareholders and 971,665,288 shares, with 99.7% registered in the Verdipapirsentralen (VPS) - Norwegian Central Securities Depository. The table below shows the 20 largest shareholders in the Company, as at 16 April 2020.

#	Shareholder	Number of Shares	Per cent
1	Nor Energy AS	444,237,596	45.72
2	Petromal LLC	371,961,246	38.28
3	Nordnet Bank AB	13,289,774	1.37
4	Telinet Energi AS	12,864,541	1.32
5	Nordnet Livsforsikring AS	6,773,764	0.70
6	Avanza Bank AB	5,910,273	0.61
7	Gekko AS	3,948,253	0.41
8	Danske Bank A/S	3,539,789	0.36
9	UBS Switzerland AG	2,365,979	0.24
10	Ole Andreas Baksaas	2,271,809	0.23
11	Nordea Bank Abp	2,170,028	0.22
12	Sandberg JH AS	2,000,000	0.21
13	Swedbank AB	1,856,743	0.19
14	Roger Nordvedt	1,734,685	0.18
15	John Andreas Rognstad	1,700,000	0.17
16	Frank Kristian Ludvigsen	1,673,000	0.17
17	Minh Hoang Pham	1,590,000	0.16
18	Jens Pace[1]	1,498,938	0.15
19	Cresthaven Investments Pty Ltd	1,377,544	0.14
20	Øystein Brustad	1,350,000	0.14
	Subtotal	**884,113,962**	**90.99**
	Others	87,551,326	9.01
	Total	**971,665,288**	**100.00**

1 Mr. Pace's shares are not registered in the VPS; and are held as paper certificates provided by the Company when it delisted from the NSX in Australia.

Directors

The Company has six Directors at the Board. The Directors have various backgrounds and experience, offering the Group and the Company valuable perspectives on industrial, operational and financial issues.

Director	Interest in shares and options:
Eyas Alhomouz Non-Executive Director and Chairman	As at the date of this report, although Mr. Alhomouz has no personal interests in shares and options, he has influence over 371,961,246 shares as the CEO of significant shareholder Petromal LLC.
Knut Søvold Executive Director and Chief Executive Officer	As at the date of this report, 444,237,596 shares are held by NOR Energy AS, a company controlled jointly by Mr. Søvold and Mr. Ludvigsen through an indirect beneficial interest. Mr. Ludvigsen is also a member of key management.
Joseph Iskander Non-Executive Director	As at the date of this report, Mr. Iskander has no interests in shares and options.
Jens Pace Non-Executive Director	As at the date of this report, Mr. Pace holds 1,498,938 shares.
Roger Steinepreis Non-Executive Director	As at the date of this report, Mr. Steinepreis has no interests in shares and options.
Alexander Neuling Non-Executive Director	As at the date of this report, Mr. Neuling has no interests in shares and options.
Dr David King Non-Executive Director	As at the date of resignation, Dr. King held 30,000 shares.
Stephen West Executive Director and Chief Financial Officer	As at the date of resignation, Mr. West held 1,377,544 shares. Mr. West's shares were held in the name of Cresthaven Investments Pty Ltd, a company in which Mr. West has an indirect beneficial interest.
Timothy Turner Non-Executive Director	As at the date of resignation, Mr. Turner held an interest in 4,167 fully paid ordinary shares.

Company Secretary

Angeline Hicks is a Chartered Accountant with global corporate and financial experience. After gaining her qualifications at Deloitte, Ms. Hicks furthered her career in the banking industry in London for eight years, working for investment banks such as Barclays Capital, Credit Suisse and JP Morgan, focusing on managing compliance and corporate and financial reporting. Ms. Hicks is an Associate of the Governance Institute of Australia and also performs the role of Company Secretary for companies listed on the Australian Securities Exchange.

Meetings of Directors

The number of Directors' meetings (including committees) held during the period each Director held office during the financial year and the number of meetings attended by each Director is shown below:

	Audit Committee Meetings		Directors' Meetings	
Director	Eligible to attend	Attended	Eligible to attend	Attended
E Alhomouz	–	–	3	3
K Søvold	–	–	3	3
J Pace	–	1	4	4
S West	–	1	4	4
J Iskander	–	–	3	3
D King	1	1	4	2
B Moe	1	1	3	3
T Turner	1	1	4	4

Cyprus company, PetroNor E&P Ltd

	Directors' Meetings	
Director	Eligible to attend	Attended
E Alhomouz	6	5
K Søvold	6	6
G Ludvigsen	6	6
A Georghiou	5	5
N Kouyialis	5	5
H Marshad	5	4

In addition to meetings of Directors held during the year, due to the number and diversified location of the Directors, a number of matters are authorised by the Board of Directors via circulating resolutions. During the current year, two circulating resolutions were authorised by the Board of Directors. There were no Remuneration Committee or Continuous Disclosure Committee meetings during the year, as any relevant matters were discussed during the Directors' Meetings.

Indemnifying Directors and officers

In accordance with the Constitution, except as may be prohibited by the Corporations Act 2001, every Director, principal Executive Officer or Secretary of the Company shall be indemnified out of the property of the Company against any liability incurred by him in his capacity as Director, principal Executive Officer or Secretary of the Company or any related corporation in respect of any act or omission whatsoever and howsoever occurring or in defending any proceedings, whether civil or criminal.

Indemnification of auditors

To the extent permitted by law, the Company has agreed to indemnify its auditors, BDO Audit (WA) Pty Ltd ("BDO"), as part of the terms of its audit engagement agreement against claims by third parties arising from the audit (for an unspecified amount). No payment has been made to indemnify BDO during or since the financial year.

Health, Safety and Environment

Health, Safety and Environment (HSE) policies are essential for PetroNor with the goal to avoid accidents and incidents and minimize the impact of its activities on the environment. PetroNor performs all its activities with focus on and respect for people and the environment. The Board believes this is a key condition for creating value in a very demanding business. The Group's objective for health, environment, safety and quality (HSEQ) is zero accidents and zero unwanted incidents in all activities. The Group strives towards performing all its activities with no harm to people or the environment. PetroNor experienced no accidents, injuries, incidents or any environmental claims during the year.

Time lost due to employee illness or accidents was negligible. Employee safety is of the highest priority, and the Group is continuously working towards identifying and employing administrative and technical solutions that ensure a safe and efficient workplace.

The Group is in the process of establishing a set of operational guidelines building on its principles of Corporate Governance, covering critical operational aspects ranging from ethical issues and practical travel advice to delegation of authority matrices.

The oil and gas assets located in West Africa imply frequent travel, and the Group seeks to ensure adequate safety levels for management and employees travelling.

With its non-operated licences, PetroNor is dependent on the efforts of the operators with respect to achieving physical results in the field. However, the Group has chosen to take an active role in all licence committees with the conviction that high safety standards are the best means to achieve successful operations. Through this involvement, the Group can influence the choice of technical solutions, vendors and quality of applied procedures and practices.

The Group's operations have been conducted by the operators on behalf of the licensees, at acceptable HSE standards and the Operator of PNGF Sud is reporting regularly on all key HSE indicators. No accidents that resulted in loss of human lives or serious damage to people or property have been reported.

In October 2019, Non-Executive Director Bjarne Moe sadly passed away unexpectedly. Bjarne had been a valuable contributor towards the Company since joining the Board of what was then African Petroleum in 2013.

To the best of the Group's knowledge, all operations have been conducted within the limits set by approved environmental regulatory authorities.

The Company is aware of its environmental obligations with regards to its exploration activities and ensures that it complies with the relevant environmental regulations when carrying out any exploration work. There have been no significant known breaches of the Company's exploration licence conditions or any environmental regulations to which it is subject.

Significant changes in the state of affairs

There have been no significant changes in the Company's state of affairs during the current year.

Options

Unissued shares under option

At the date of this report unissued ordinary shares of the Company under option are:

Expiry date	Exercise price/NOK	Exercise price /USD equivalent at 31 December 2019	Number under option
15 November 2020	1.70	0.19	190,000
22 December 2020	1.70	0.19	700,000
11 January 2022	2.50	0.28	213,400
31 May 2022	7.75	0.88	1,176,070
Total			**2,279,470**

Shares issued on the exercise of options

During the current year, no ordinary shares were issued on the exercise of options (2018: nil).

Proceedings on behalf of Company

No person has applied for leave of Court to bring proceedings on behalf of the Company or intervene in any proceedings to which the Company is a party for the purpose of taking responsibility on behalf of the Company for all or any part of those proceedings.

The Company was not a party to any such proceedings during the year.

Significant events after the balance date

Board restructure

On 29 February 2020, Jens Pace stepped down as Chief Executive Officer but remained on the Board as a Non-Executive Director. Chief Operating Officer, Knut Søvold, was immediately appointed the Chief Executive Officer. Also, on 29 February 2020, Stephen West resigned as the Chief Financial Officer and Executive Director.

Non-Executive Directors David King and Tim Turner resigned during February 2020 and were replaced by Alexander Neuling and Roger Steinepreis in April 2020.

COVID-19

Since the end of financial year, the COVID-19 outbreak is a globally-significant event impacting the health of individuals, international trade and commerce and, as a result, had a severely negative impact on global financial markets. The COVID-19 outbreak combined with the dramatic oil price decline has had a significant impact on the short-term oil prices. Consequently, this has adversely affected the Group's business.

The Company has initiated an immediate cost reduction in the Company's overheads and general administration costs. The key management salaries have been reduced with immediate effect from mid-March 2019. A full review of the Company's expenditures has been completed and cost reduction actions are implemented on a continuous basis. It has been important for the management to ensure that the cost savings initiatives have limited impact on the capabilities of the Company to continue its growth strategy even under these difficult circumstances and the new venture strategy of the Company. The implemented initiatives will reduce the "normal budget" for 12 months forward from USD 14.1 million to USD 10.5 million. This excludes any ongoing commitments such as redundancy packages and other costs which will be tapered down, going forward.

Arbitration

On 4 May 2020, the arbitration proceedings for the Group's interests in Senegal were suspended until 2 November 2020, following a mutual agreement between the parties.

Likely developments and expected results

Due to the COVID-19 outbreak and subsequent travel restrictions, the Company expects to be able to receive the governmental approval of the Aje transaction during H2 2020.

The Board wishes to thank the staff, consultants, services providers and shareholders for their continued commitment to the Company.

Auditor's independence declaration

The auditor's independence declaration for the year ended 31 December 2019 has been received and can be found on page 32 of the annual report.

Non-audit services

Non-audit services were provided by the entity's auditor's BDO, as per Note 8b. The Directors are satisfied that the provision of non-audit services is compatible with the general standard of independence for auditors imposed by the Corporations Act 2001. The nature and scope of each type of non-audit service provided means that auditor independence was not compromised.

This report is made in accordance with a resolution of the Board of Directors.

Knut Søvold
Director & Chief Executive Officer
6 May 2020

Declaration of independence
by Phillip Murdoch to the Directors of PetroNor E&P Limited

As lead auditor of PetroNor E&P Limited for the year ended 31 December 2019, I declare that, to the best of my knowledge and belief, there have been:

1. No contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and
2. No contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of PetroNor E&P Limited and the entities it controlled during the period.

Phillip Murdoch
Director

BDO Audit (WA) Pty Ltd
Perth, 6 May 2020

Consolidated statement of profit or loss and other comprehensive income

	Note	2019 USD'000	2018 USD'000
Revenue	5	**102,760**	101,069
Cost of sales	6	**(37,207)**	(41,577)
Gross profit		**65,553**	59,492
Other operating income	7	**9**	491
Administrative expenses	8	**(19,793)**	(10,090)
Profit from operations		**45,769**	49,893
Finance expense	9	**(1,822)**	(1,623)
Finance income		**–**	–
Foreign exchange loss		**(440)**	(88)
Share based payment	23	**(19,374)**	–
Profit before tax		**24,133**	48,182
Tax expense	10	**(29,894)**	(31,124)
(Loss) / profit for the year		**(5,761)**	17,058
Other comprehensive income:			
Exchange gains arising on translation of foreign operations		**–**	–
Total comprehensive (loss) / income		**(5,761)**	17,058
(Loss) / spaces either side of / profit for the year attributable to:			
Owners of the parent		**(13,364)**	7,838
Non-controlling interest		**7,603**	9,220
		(5,761)	17,058
Total comprehensive (loss) / income attributable to:			
Owners of the parent		**(13,364)**	7,838
Non-controlling interest		**7,603**	9,220
		(5,761)	17,058
		USD cents	USD cents
Earnings per share attributable to members:			
Basic and diluted (loss)/profit per share	11	**(1.17)**	0.96

The accompanying notes form part of these financial statements

Consolidated statement of financial position

	Note	As at 31 December 2019 USD'000	As at 31 December 2018 USD'000
Assets			
Current assets			
Inventories	12	**3,233**	2,570
Trade and other receivables	13	**24,772**	28,210
Cash and cash equivalents	14	**27,891**	7,926
		55,896	38,706
Non-current assets			
Property, plant and equipment	16	**22,587**	12,580
Intangible assets	17	**4,691**	5,565
		27,278	18,145
Total assets		**83,174**	56,851
Liabilities			
Current liabilities			
Trade and other payables	18	**34,602**	9,653
Loans and borrowings	19	**12,941**	5,000
		47,543	14,653
Non-current liabilities			
Loans and borrowings		**–**	2,083
Provisions	20	**14,373**	13,496
		14,373	15,579
Total liabilities		**61,916**	30,232
NET ASSETS		**21,258**	26,619
Issued capital and reserves attributable to owners of the parent			
Share capital	21	**17,735**	120
Retained earnings	22	**(11,226)**	13,688
		6,509	13,808
Non-controlling interests		**14,749**	12,811
TOTAL EQUITY		**21,258**	26,619

The accompanying notes form part of these financial statements

The financial statements were approved and authorised for issue by the Board of Directors on 6 May 2020 and were signed on its behalf by Knut Søvold.

Consolidated statement of changes in equity

	Note	Issued capital USD'000	Share-based payment reserve USD'000	Foreign currency translation reserve USD'000	Retained earnings USD'000	Non-controlling interest USD'000	Total USD'000
BALANCE AT 1 JANUARY 2019		**120**	**–**	**–**	**13,688**	**12,811**	**26,619**
(Loss) / profit for the year		**–**	**–**	**–**	**(13,364)**	**7,603**	**(5,761)**
Other comprehensive income		**–**	**–**	**–**	**–**	**–**	**–**
Total comprehensive loss for the year		**–**	**–**	**–**	**(13,364)**	**7,603**	**(5,761)**
Issue of capital	21	**17,615**	**–**	**–**	**–**	**–**	**17,615**
Exercise of share options		**–**	**–**	**–**	**–**	**–**	**–**
Dividends paid during the year		**–**	**–**	**–**	**(11,550)**	**(5,665)**	**(17,215)**
Share-based payments		**–**	**–**	**–**	**–**	**–**	**–**
BALANCE AT 31 DECEMBER 2019		**17,735**	**–**	**–**	**(11,226)**	**14,749**	**21,258**
For the year ended 31 December 2018							
BALANCE AT 1 JANUARY 2018		120	–	–	5,580	5,713	11,683
Profit for the year		–	–	–	7,838	9,220	17,058
Other comprehensive income		–	–	–	–	–	–
Total comprehensive loss for the year		120	–	–	7,838	9,220	17,058
Issue of capital		–	–	–	–	3	3
Exercise of share options		–	–	–	–	–	–
Dividends paid during the year		–	–	–	–	(2,125)	(2,125)
Share-based payments		–	–	–	–	–	–
BALANCE AT 31 DECEMBER 2018		120	–	–	13,688	12,811	26,619

The accompanying notes form part of these financial statements

Consolidated statement of cash flows

	Note	For the year ended 31 December 2019 USD'000	For the year ended 31 December 2018 USD'000
Cash flows from operating activities			
Profit for the year		**24,133**	48,182
Adjustments for:			
Depreciation and amortisation		**3,323**	3,206
Unwinding of discount on decommissioning liability		**877**	824
Impairment of goodwill		**9**	–
Share-based payment expense		**16,433**	–
		44,775	52,212
Decrease / (increase) in trade and other receivables		**6,724**	(9,807)
Increase in advance against decommissioning cost		**(3,286)**	(11,360)
Increase in inventories		**(663)**	(201)
Increase / (decrease) in trade and other payables		**24,950**	(784)
Cash generated from operations		**27,725**	30,060
Income taxes paid		**(29,894)**	(31,124)
Net cash flows from operating activities		**42,606**	(1,064)
Investing activities			
Purchases of property, plant and equipment		**(12,466)**	(4,037)
Net cash flows from investing activities		**(12,466)**	(4,037)
Financing activities			
Issue of ordinary shares		**1,182**	–
Proceeds from loans and borrowings		**12,917**	10,000
Repayment of loans and borrowings		**(7,059)**	(2,917)
Dividends paid to non-controlling interest		**(5,665)**	(2,125)
Dividends paid		**(11,550)**	–
Net cash (used in) / from financing activities		**(10,175)**	**4,958**
Net increase / (decrease) in cash and cash equivalents		**19,965**	(143)
Cash and cash equivalents at beginning of year		**7,926**	8,069
Cash and cash equivalents at end of year	14	**27,891**	7,926

The accompanying notes form part of these financial statements

1. Corporate information

The financial report of the Company and its subsidiaries (together the “Group”) for the year ended 31 December 2019 was authorised for issue in accordance with a resolution of the Directors on 6 May 2020.

PetroNor E&P Limited is a ‘for profit entity’ and is a Company limited by shares incorporated in Australia. Its shares are publicly traded on the Oslo Axess (code: PNOR), a regulated marketplace of the Oslo Stock Exchange, Norway. The principal activities of the Group are the exploration and production of crude oil.

On 12 September 2019, the Company changed its name from African Petroleum Corporation Limited to PetroNor E&P Limited.

2. Basis of preparation

The financial report is a general-purpose financial report, which has been prepared in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board. The financial report has been prepared on a historical cost basis.

The financial report is presented in United States Dollars, which is also the functional currency for the Company and all material subsidiaries, and all values are rounded to the thousand dollars unless otherwise stated.

The financial report is presented as a continuance of the activities of the Cypriot company PetroNor E&P Ltd, using the reverse acquisition rules for the merger that took place on 30 August 2019, Notes 4 & 23.

Compliance statement

The financial report complies with Australian Accounting Standards. The financial report also complies with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

Going concern

The underlying business of the Group created a net profit after tax of USD 13.6 million for 2019, whereas accounting-wise the Group incurred a net loss after tax of USD 5.76 million, due to recognising the extraordinary USD 19.37 million share-based payment expense for the reverse acquisition transaction. As at 31 December 2019, the Group’s current assets exceeded its current liabilities by USD 8.4 million and had unrestricted cash of USD 27 million.

Since the end of the financial year, the COVID-19 outbreak is a globally significant event impacting the health of individuals, international trade and commerce and, as a result had a negative impact on global financial markets. Consequently, this has adversely affected the Group’s business and its ability to operate efficiently. During March 2020, Governments of all the countries in which the Group operates closed borders to international travellers and introduced social distancing measures.

Additionally, since the end of the financial year, global oil prices have collapsed with the price of Brent crude falling from a level of USD 60 - 70 per barrel to a current level of around USD 30 per barrel and oil prices may be depressed throughout 2020. However, for 2021, market forecasters are predicting a significant recovery in oil price which is reflected in a contango on forward oil prices today, however as at the date of this report, it is uncertain what the effect will be on the Group moving forward.

These conditions indicate a material uncertainty that may cast a significant doubt about the entity’s ability to continue as a going concern and, therefore, that it may be unable to realise its assets and discharge its liabilities in the normal course of business. This financial report has been prepared on the going concern basis which assumes the continuity of normal business activity and the realisation of assets and the settlement of liabilities in the normal course of business.

The Group has already implemented multiple cost saving measures, including streamlining of the organisation, initiating a simplification of the group structure and salary reductions as detailed in Note 24b and will continue to manage its activities with the objective of ensuring that it has sufficient cash reserves to meet its revised budgeted expenditures for the next twelve months from the date of this report.

2. Basis of preparation continued

As at the signing date of this report:

- outstanding amounts due to related parties Petromal LLC and NOR Energy AS for the cash consideration of the reverse transaction include USD 2.0 million and USD 3.6 million respectively; and
- the Group has been able to secure a refinancing for the loan payable to Rasmala of USD 12 million, (Note 19).

There are material uncertainties on the going concern status of the Group, due to the current challenging market conditions for the oil and gas industry as well as those created by the COVID-19 pandemic, the uncertain impact of these factors on the Group's operations, and the material uncertainty related to the Group's ability to renegotiate the terms of outstanding liabilities to related parties due for immediate repayment.

In the opinion of the Directors, the Group will be in a position to continue to meet its liabilities and obligations for a period of at least twelve months from the date of signing this report, having regard to the initiatives already underway and the expectation that the Group will be able to implement further financing strategies and commercial plans to be able to secure and execute its planned activities over the same period.

If the Group is not successful in executing these initiatives and / or in renegotiating the terms of outstanding liabilities to related parties, it may be unable to realise its assets and discharge its liabilities in the normal course of business and at the amounts stated in the financial report.

This financial report does not include any adjustments relating to the recoverability and classification of recorded asset amounts or to the amounts and classification of liabilities that might be necessary should the Group not continue as a going concern.

3. Summary of accounting policies

Accounting policies are selected and applied in a manner which ensures that the resulting financial information satisfies the concepts of relevance and reliability, thereby ensuring that the substance of the underlying transactions or other events is reported.

The following is a summary of the material accounting policies adopted by the Group in the preparation of the financial report. The accounting policies have been consistently applied, unless otherwise stated.

3a. Adoption of new and revised accounting standards

In the current period, the Group has adopted all of the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board (the 'AASB') that are relevant to its operations and effective for reporting periods beginning on 1 January 2019. The Group has not elected to early adopt any new standards or amendments.

The Directors note that the impact of the initial application of the Standards and Interpretation is not yet known or is not reasonably estimable and is currently being assessed. At the date of authorisation of the financial statements, the Standards and Interpretations that were issued but not yet effective are listed below.

Standard/Interpretation	Effective
AASB 2019-1 Amendments to Australian Accounting Standards – Reference to the Conceptual Frameworks	1 Jan 2020
AASB 2018-6 Amendments to Australian Accounting Standards – Definition of a Business	1 Jan 2020
AASB 2018-7 Amendments to Australian Accounting Standards – Definition of Material	1 Jan 2020
AASB 2019-2 Amendments to Australian Accounting Standards – Implementation of AASB 1059	1 Jan 2020
AASB 2019-3 Amendments to Australian Accounting Standards – Interest Rate Benchmark Reform	1 Jan 2020
AASB 2019-5 Amendments to Australian Accounting Standards – Disclosure of the Effect of New IFRS Standards Not Yet Issued in Australia	1 Jan 2020
AASB 17 Insurance Contracts	1 Jan 2021
AASB 2014-10 Amendments to Australian Accounting Standards – Sale or Contribution of Assets between an Investor and its Associate or Joint Venture	1 Jan 2022

At the date of authorisation of the financial statements, the following IASB Standards and IFRIC Interpretations were also in issue but not yet effective, although Australian equivalent Standards and Interpretations have not yet been issued.

None

3b. Consolidation

The consolidated financial statements comprise the financial statements of PetroNor E&P Limited ("the Company") and its subsidiaries for the year ended 31 December 2019 (together the Group).

Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:

- Power over the investee (ie existing rights that give it the current ability to direct the relevant activities of the investee)
- Exposure, or rights, to variable returns from its involvement with the investee, and
- The ability to use its power over the investee to affect its returns

When the Group has less than a majority of the voting or similar rights of an investee, the Group considers all relevant facts and circumstances in assessing whether it has power over an investee, including:

- The contractual arrangement with the other vote holders of the investee
- Rights arising from other contractual arrangements
- The Group's voting rights and potential voting rights

The Group reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of during the year are included in the statement of comprehensive income from the date the Group gains control until the date the Group ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income (OCI) are attributed to the equity holders of the parent of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies. All intra-group assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction. If the Group loses control over a subsidiary, it:

- Derecognises the assets (including goodwill) and liabilities of the subsidiary
- Derecognises the carrying amount of any non-controlling interests
- Derecognises the cumulative translation differences recorded in equity
- Recognises the fair value of the consideration received
- Recognises the fair value of any investment retained
- Recognises any surplus or deficit in profit or loss
- Reclassifies the parent's share of components previously recognised in OCI to profit or loss or retained earnings, as appropriate, as would be required if the Group had directly disposed of the related assets or liabilities.

3c. Segment reporting

An operating segment is a component of an entity that engages in business activities from which it may earn revenues and incur expenses (including revenues and expenses relating to transactions with other components of the same entity), whose operating results are regularly reviewed by the entity's chief operating decision-makers to make decisions about resources to be allocated to the segments and assess their performance and for which discrete financial information is available. This includes start-up operations which are yet to earn revenues.

Operating segments have been identified based on the information available to chief operating decision-makers – being the Board and the executive management team.

Operating segments that meet the quantitative criteria as prescribed by AASB 8 are reported separately. However, an operating segment that does not meet the quantitative criteria is still reported separately where information about the segment would be useful to users of the financial statements.

Information about other business activities and operating segments that are below the quantitative criteria are combined and disclosed in a separate category called "all other segments".

3. **Summary of accounting policies** continued

3d. Foreign currency translation

Functional and presentation currency

The Company has elected to use United States Dollars, being the functional currency of all major subsidiaries in the Group, as its presentation currency. Where the functional currencies of entities within the consolidated group differ from United States Dollars, they have been translated into United States Dollars. The functional currency of PetroNor E&P Limited is United States Dollars.

Transactions and balances

Transactions in foreign currencies are initially recorded in the functional currency by applying the exchange rates ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the rate of exchange ruling at the reporting date and any gains or losses are recognised in the income statement.

Non-monetary items that are measured in terms of historical cost in the foreign currency are translated using the exchange rate as at the date of the initial transaction. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined.

Translation of Group Companies' functional currency to presentation currency

On consolidation, the assets and liabilities of foreign operations are translated into United States Dollars at the rate of exchange prevailing at the reporting date and their income and expenditure are translated at exchange rates prevailing at the dates of the transactions. The exchange differences arising on translation for consolidation are recognised in other comprehensive income. On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss.

3e. Cash and cash equivalents

Cash and cash equivalents include cash on 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 are shown within short-term borrowings in current liabilities on the Statement of Financial Position.

3f. Trade receivables

Trade receivables are amounts due from customers for goods sold or services performed in the ordinary course of business. They are generally due for settlement within 30 to 90 days and therefore are all classified as current. Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, when they are recognised at fair value. The group holds the trade receivables with the objective to collect the contractual cash flows and therefore measures them subsequently at amortised cost using the effective interest method.

Trade receivables are written off when there is no reasonable expectation of recovery. Indicators that there is no reasonable expectation of recovery include, amongst others, the failure of a debtor to engage in a repayment plan with the group, and a failure to make contractual payments for a period of greater than 120 days past due.

Impairment losses on trade receivables and contract assets are presented as net impairment losses within operating profit. Subsequent recoveries of amounts previously written off are credited against the same line item.

3g. Inventory

The crude oil inventory and the material and supplies inventory are valued at the lower of cost and net realisable value. Cost is determined using the weighted average method. Net realisable value is the estimated selling price, less applicable selling expenses. The cost of inventory includes all costs related to bringing the inventory to its current condition, including processing costs, labour costs, supplies, direct and allocated indirect operating overhead and depreciation expense, where applicable, including allocation of fixed and variable costs to inventory.

3h. Property plant and equipment

Oil & gas production assets

Oil and gas production assets are aggregated exploration and evaluation tangible assets and development expenditures associated with the production of proved reserves.

The cost of development and production assets also includes the cost of acquisitions and purchases of such assets, directly attributable overheads and the cost of recognising provisions for future restoration and decommissioning.

Where major and identifiable parts of the production assets have different useful lives, they are accounted for as separate items of property, plant and equipment. Costs of minor repairs and maintenance are expensed as incurred.

Depreciation

Oil and gas properties are depreciated using the unit-of-production method. Unit-of production rates are based on 1P proved reserves, which are oil, gas and other mineral reserves estimated to be recovered from existing facilities using current operating methods. Oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the field storage tank.

Field infrastructure exceeding beyond the life of the field is depreciated over the useful life of the infrastructure using a straight-line method.

Property, plant and equipment not associated with exploration and production activities are carried at cost less accumulated depreciation. These assets are also evaluated for impairment. Depreciation of other assets is calculated on a straight-line basis as follows:

Computer equipment	20 – 33.33%
Furniture, fixtures & fittings	10 – 33.33%
Motor vehicles	20%

3i. Exploration and evaluation expenditure

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. For each area of interest, expenditure incurred in the acquisition of rights to explore and all costs directly associated with holding the licence such as rental, training and corporate and social responsibility are capitalised as exploration and evaluation intangible assets. Signature bonuses required by licence agreements are capitalised as exploration and evaluation intangible assets. Other costs directly associated with the licence are expensed as incurred.

Exploration, evaluation and development expenditure is recorded at historical cost and allocated to cost pools on an area of interest. Expenditure on an area of interest is capitalised and carried forward where rights to tenure of the area of interest are current and:

it is expected to be recouped through successful development and exploitation of the area of interest or alternatively by its sale; or

exploration and evaluation activities are continuing in an area of interest but at reporting date have not yet reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves.

Accumulated costs in respect of areas of interest which are abandoned are written off in full against profit in the period in which the decision to abandon the area is made.

Projects are advanced to development status when it is expected that further expenditure can be recouped through sale or successful development and exploitation of the area of interest.

All capitalised costs are subject to commercial and management review, as well as review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through the statement of profit or loss and other comprehensive income.

3. Summary of accounting policies continued

When proved reserves of oil and natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and (if required) any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties.

Proceeds from disposal or farm-out transactions of intangible exploration assets are used to reduce the carrying amount of the assets. When proceeds exceed the carrying amount, the difference is recognised as a gain. When the Group disposes of its full interests, gains or losses are recognised in accordance with the policy for recognising gains or losses on sale of plant, property and equipment.

3j. Borrowing costs

Borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset are added to the cost of the asset during the period of time that is required to complete and prepare the asset for its intended use. Borrowing costs are capitalised to the extent that funds are borrowed specifically for the purpose of obtaining a qualifying asset. To the extent that funds are borrowed generally and used for the purpose of obtaining a qualifying asset, the amount of borrowing costs eligible for capitalisation is determined by applying a capitalisation rate to the expenditures on that asset. All other borrowing costs are expensed as incurred.

3k. Revenue

(i) Revenue from petroleum products

Revenue from the sale of crude oil is recognised when a customer obtains control (“sales” or “lifting” method), normally this is when title passes at point of delivery. Revenues from production of oil properties are recognised based on actual volumes lifted and sold to customers during the period. Under a production sharing contract, where the group is required to pay profit oil tax and royalties on production of crude oil, such payments are settled in kind (where the government lift the crude it is entitled to). The Group presents a gross-up of the profit oil tax as an income tax expense with a corresponding increase in oil and gas revenues and any associated royalties are included in the cost of sales.

The Group assesses whether it acts as a principal or agent in each of its revenue arrangements. The Group has concluded that in all sales transactions it acts as a principal.

(ii) Variable consideration

If the consideration in a contract includes a variable amount, the Group recognises this amount as revenue only to the extent that it is highly probable that a significant reversal will not occur in the future.

Interest

Interest revenue is recognised on a time-proportional basis using the effective interest method. This is a method of calculating the amortised cost of a financial asset and allocating the interest income over the relevant period using the effective interest rate, which is the rate that exactly discounts the estimated future cash receipts through the expected useful life of the financial asset to the net carrying amount of the financial asset.

3l. Leases

(i) Right-of-use assets

The Group recognises right-of-use assets at the commencement date of the lease (ie, the date the underlying asset is available for use). Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. Unless the Group is reasonably certain to obtain ownership of the leased asset at the end of the lease term, the recognised right-of-use assets are depreciated on a straight-line basis over the shorter of its estimated useful life and the lease term. Right-of-use assets are subject to impairment.

(ii) Lease liabilities

At the commencement date of the lease, the Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. The lease payments include fixed payments (including in-substance fixed payments) less any lease incentives receivable, variable lease payments that depend on an index or a rate, and amounts expected to be paid under residual value guarantees. The lease payments also include the exercise price of a purchase option reasonably certain to be exercised by the Group and payments of penalties for terminating a lease, if the lease term reflects the Group exercising the option to terminate. The variable lease payments that do not depend on an index or a rate are recognised as an expense in the period on which the event or condition that triggers the payment occurs. In calculating the present value of lease payments, the Group uses the incremental borrowing rate at the lease commencement date if the interest rate implicit in the lease is not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the in-substance fixed lease payments or a change in the assessment to purchase the underlying asset.

3m. Taxes

The income tax expense or benefit for the period consists of two components: current and deferred tax.

The current income tax payable or recoverable is calculated using the tax rates and legislation that have been enacted or substantively enacted at year-end in each of the jurisdictions and includes any adjustments for taxes payable or recovery in respect of prior periods.

Deferred tax assets and liabilities are determined using the balance sheet liability method based on temporary differences between the carrying value of assets and liabilities for financial reporting purposes and their tax bases. In calculating the deferred tax assets and liabilities, the tax rates used are those that have been enacted or substantively enacted by year-end in each of the jurisdictions and that are expected to apply when the assets are recovered, or the liabilities are settled.

Revenue-based taxes

In addition to corporate income taxes, the Group's consolidated financial statements also include and recognise as income taxes, other types of taxes on net income such as certain revenue-based taxes.

Revenue-based taxes are accounted for under AASB 112 when they have the characteristics of an income tax. This is considered to be the case when they are imposed under government authority and the amount payable is based on taxable income — rather than physical quantities produced or as a percentage of revenue — after adjustment for temporary differences. For such arrangements, current and deferred tax is provided on the same basis as described above for other forms of taxation. Obligations arising from royalty arrangements and other types of taxes that do not satisfy these criteria are accrued and included in cost of sales. The revenue taxes, except royalty, payable by the Group are considered to meet the criteria to be treated as part of income taxes.

Production-sharing arrangements

According to the production-sharing arrangement (PSA) in certain licences, the share of the profit oil to which the Government is entitled in any calendar year in accordance with the PSA is deemed to include a portion representing the corporate income tax imposed upon and due by the Group. This amount will be paid directly by the government on behalf of the Group to the appropriate tax authorities.

The income tax expense

The current income tax is calculated using the PSA, paid in barrels and booked as income tax and also shown as revenue.

Sales tax

Revenues, expenses and assets are recognised net of the amount of sales tax except:

Where the sales tax incurred on a purchase of assets or services is not recoverable from the taxation authority, in which case, the sales tax is recognised as part of the cost of acquisition of the asset or as part of the expense item as applicable.

Receivables and payables that are stated with the amount of sales tax included.

3. Summary of accounting policies continued

The net amount of sales tax recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the statement of financial position.

Current and deferred tax balances attributable to amounts recognised directly in equity are also recognised directly in equity.

3n. Employee benefits

Provision is made for benefits accruing to employees in respect of wages and salaries, annual leave and long service leave when it is probable that settlement will be required, and they are capable of being measured reliably. Provisions made in respect of employee benefits expected to be settled within 12 months are measured at their nominal values using the remuneration rate expected to apply at the time of settlement. Provisions made in respect of employee benefits, which are not due to be settled within 12 months are determined using the projected unit credit method.

3o. Trade and other payables

Trade and other payables are carried at amortised cost and due to their short-term nature, they are not discounted.

3p. Provisions

i. General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Group expects some or all of the provision to be reimbursed, for example under an insurance contract, the reimbursement is recognised as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is recognised through profit and loss net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as interest expense. The present obligation under onerous contracts is recognised as a provision.

ii. Decommissioning liability

A decommissioning liability is recognised when the Group has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. A corresponding amount equivalent to the obligation is also recognised as part of the cost of the related production plant and equipment. The amount recognised in the estimated cost of decommissioning, discounted to its present value. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to production plant and equipment. The unwinding of the discount on the decommissioning liability is included as a finance cost.

An escrow account is maintained by the operator of the licence and is governed by a joint operating agreement and the Congolese Government rules. The Group's share, paid against the decommissioning liability until the balance sheet date, is classified as an advance against decommissioning liability in current assets.

3q. Share capital

Contributed equity is recognised at the fair value of the consideration received by the Group, less any capital raising costs in relation to the issue.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

3r. Dividend distribution

Dividend distribution to the Company's shareholders is recognised as a liability in the Group's financial statements in the period in which the dividends are declared and appropriately authorised or approved by the Company's Shareholders' General Meeting. Interim dividends proposed by the Board of Directors are recognised as liabilities upon declaration.

3s. Share-based payments

The fair value of shares awarded is measured at the share price on the date the shares are granted. For options awarded, the fair value is measured at grant date using the Black-Scholes model. Shares and options which are subject to vesting conditions, are recognised over the estimated vesting period during which the holder becomes unconditionally entitled to the shares or options.

When the terms of an equity-settled award are modified, the minimum expense recognised is the expense had the terms had not been modified, if the original terms of the award are met. An additional expense is recognised for any modification that increases the total fair value of the share-based payment transaction; or is otherwise beneficial to the employee as measured at the date of modification.

3t. Financial instruments

A financial instrument is any contract that gives rise to a financial asset of any one entity and a financial liability or equity instrument of another entity.

i) Financial assets

Financial assets are classified, at initial recognition, as subsequently measured at amortised cost, fair value through other comprehensive income (OCI), and fair value through profit or loss, as appropriate.

The classification of financial assets at initial recognition depends on the financial asset's contractual cash flow characteristics and the Group's business model for managing them. With the exception of trade receivables that do not contain a significant financing component or for which the Group has applied the practical expedient, the Group initially measures a financial asset at its fair value plus, in the case of financial assets not subsequently measured at fair value through profit or loss, transaction costs that are attributable to the acquisition of the financial asset.

In order for a financial asset to be classified and measured at amortised cost or fair value through OCI, it needs to give rise to cash flows that are solely payments of principal and interest (SPPI) on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level.

The Group's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both.

Purchases or sales of financial assets that require delivery of assets within a time frame established by regulation or convention in the marketplace (regular way trades) are recognised on the trade date, i.e., the date that the Group commits to purchase or sell the asset.

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The group derecognises financial assets when the contractual rights to the cash flows expire or the financial asset is transferred to a third party. This includes the derecognition of receivables for which discounting arrangements are entered into. The classification depends on the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset.

Subsequent measurement

For purposes of subsequent measurement, financial assets are classified in 4 categories:
- Financial assets at amortised cost (debt instruments)
- Financial assets at fair value through OCI with recycling of cumulative gains and losses (debt instruments)
- Financial assets designated at fair value through OCI with no recycling of cumulative gains and losses upon derecognition (equity instruments)
- Financial assets at fair value through profit or loss

The Group has not designated any financial assets at fair value through profit or loss.

3. Summary of accounting policies continued

Financial assets at amortised cost (debt instruments)

The Group measures financial assets at amortised cost if both of the following conditions are met:

- The financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding;

Financial assets at amortised cost are subsequently measured using the effective interest (EIR) method and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

Cash equivalents

Cash equivalents are short-term, highly-liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortised cost.

Loans granted

Loans granted that have fixed or determinable payments that are not quoted in an active market are classified as financial assets at amortised cost and are measured at amortised cost using the effective interest method, less any impairment. Interest income is recognised by applying the effective interest rate.

Loans granted to related parties are normally interest-free and do not have a fixed repayment structure. These loans are classified as financial assets at amortised cost and are measured at amortised cost using the effective interest method, less any impairment. Effective interest rate being zero in this case.

Derecognition

A financial asset (or, where applicable, a part of a financial asset or part of a group of similar financial assets) is primarily derecognised (ie, removed from the Group's consolidated statement of financial position) when:

The rights to receive cash flows from the asset have expired or the Group has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a 'pass-through' arrangement; and either (a) the Group has transferred substantially all the risks and rewards of the asset, or (b) the Group has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

When the Group has transferred its rights to receive cash flows from an asset or has entered into a pass-through arrangement, it evaluates if, and to what extent, it has retained the risks and rewards of ownership. When it has neither transferred nor retained substantially all of the risks and rewards of the asset, nor transferred control of the asset, the Group continues to recognise the transferred asset to the extent of its continuing involvement. In that case, the Group also recognises an associated liability. The transferred asset and the associated liability are measured on a basis that reflects the rights and obligations that the Group has retained.

Impairment of financial assets

The Group recognises an allowance for expected credit losses (ECLs) for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Group expects to receive, discounted at an approximation of the original effective interest rate. The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms.

ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12 months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Group applies a simplified approach in calculating ECLs. Therefore, the Group does not track changes in credit risk, but instead recognises a loss allowance based on lifetime ECLs at each reporting date. The Group has established a provision matrix that is based on its historical credit-loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment.

The Group considers a financial asset in default when contractual payments are 90 days past due. However, in certain cases, the Group may also consider a financial asset to be in default when internal or external information indicates that the Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Group. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

ii) Financial liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The Group's financial liabilities include trade and other payables, loans and borrowings, including bank overdrafts, financial guarantee contracts, and derivative financial instruments.

Subsequent measurement

The measurement of financial liabilities depends on their classification, as described below:

Financial liabilities at fair value through profit or loss.

Financial liabilities at fair value through profit or loss include derivative financial liabilities, financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are incurred for the purpose of repurchasing in the near term. This category also includes derivative financial instruments entered into by the Group that are not designated as hedging instruments in hedge relationships as defined by AASB 9. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognised in the statement of profit or loss.

Financial liabilities designated upon initial recognition at fair value through profit or loss are designated at the initial date of recognition, and only if the criteria in AASB 9 are satisfied.

Loans and borrowings

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest rate ("EIR") method. Gains and losses are recognised in profit or loss when the liabilities are derecognised as well as through the EIR amortisation process.

Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included as finance costs in the statement of profit or loss.

This category generally applies to interest-bearing loans and borrowings.

3. Summary of accounting policies continued

Derecognition

A financial liability is derecognised when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the statement of profit or loss.

iii) Offsetting of financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated statement of financial position if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis, to realise the assets and settle the liabilities simultaneously.

3u. Joint arrangements

Joint arrangements are arrangements of which two or more parties have joint control. Joint control is the contractual agreed sharing of control of the arrangement which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control. Joint arrangements are classified as either a joint operation or joint venture, based on the rights and obligations arising from the contractual obligations between the parties to the arrangement.

To the extent the joint arrangement provides the Company with rights to the individual assets and obligations arising from the joint arrangement, the arrangement is classified as a joint operation and as such, the Company recognises its:
- Assets, including its share of any assets held jointly;
- Liabilities, including its share of any liabilities incurred jointly;
- Revenue from the sale of its share of the output arising from the joint operation;
- Share of revenue from the sale of the output by the joint operation; and
- Expenses, including its share of any expenses incurred jointly.

To the extent the joint arrangement provides the Company with rights to the net assets of the arrangement, the investment is classified as a joint venture and accounted for using the equity method. Under the equity method, the cost of the investment is adjusted by the post-acquisition changes in the Company’s share of the net assets of the venture.

3v. Current versus non-current classification

The Group presents assets and liabilities in the statement of financial position based on current/non-current classification. An asset is current when it is either:
- Expected to be realised or intended to be sold or consumed in the normal operating cycle;
- Held primarily for the purpose of trading;
- Expected to be realised within 12 months after the reporting period;
- Cash or cash equivalent unless restricted from being exchanged or used to settle a liability for at least 12 months after the reporting period.

All other assets are classified as non-current.

A liability is current when either:
- It is expected to be settled in the normal operating cycle
- It is held primarily for the purpose of trading
- It is due to be settled within 12 months after the reporting period
- There is no unconditional right to defer the settlement of the liability for at least 12 months after the reporting period

The Group classifies all other liabilities as non-current.

Deferred tax assets and liabilities are classified as non-current assets and liabilities.

3w. Business combinations and goodwill

In order to consider an acquisition as a business combination, the acquired asset or groups of assets must constitute a business (an integrated set of operations and assets conducted and managed for the purpose of providing a return to the investors). The combination consists of inputs and processes applied to these inputs that have the ability to create output. Acquired businesses are included in the financial statements from the transaction date. The transaction date is defined as the date on which the company achieves control over the financial and operating assets. This date may differ from the actual date on which the assets are transferred. Comparative figures are not adjusted for acquired, sold or liquidated businesses. On acquisition of a licence that involves the right to explore for and produce petroleum resources, it is considered in each case whether the acquisition should be treated as a business combination or an asset purchase. Generally, purchases of licences in a development or production phase will be regarded as a business combination. Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest (NCI) in the acquiree. For each business combination, the Group elects whether to measure NCI in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition related costs are expensed as incurred and included in administrative expenses.

When the Group acquires a business, it assesses the assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree. Those acquired petroleum reserves and resources that can be reliably measured are recognised separately in the assessment of fair values on acquisition. Other potential reserves, resources and rights, for which fair values cannot be reliably measured, are not recognised separately, but instead are subsumed in goodwill.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Contingent consideration classified as an asset or liability that is a financial instrument and within the scope of AASB 9 Financial Instruments: Recognition and Measurement is measured at fair value, with changes in fair value recognised either in the statement of profit or loss or as a change to other comprehensive income. If the contingent consideration is not within the scope of AASB 9, it is measured in accordance with the appropriate AASB. Contingent consideration that is classified as equity is not remeasured, and subsequent settlement is accounted for within equity.

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognised for NCI over the fair value of the identifiable net assets acquired and liabilities assumed. If the fair value of the identifiable net assets acquired is in excess of the aggregate consideration transferred (bargain purchase), before recognising a gain, the Group reassesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognised at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, then the gain is recognised in the statement of profit or loss and other comprehensive income.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash generating units (CGUs) that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill forms part of a CGU and part of the operation in that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal.

Goodwill disposed of in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained.

4. Significant accounting judgements, estimates and assumptions

The Directors evaluate estimates and judgements incorporated in the Financial Report based on historical knowledge and best-available current information. Estimates assume a reasonable expectation of future events and are based on current trends and economic data, obtained both externally and within the Group.

Management has identified the following critical accounting policies for which significant judgements, estimates and assumptions are made. Actual results may differ from these estimates under different assumptions and conditions and may materially affect financial results or the financial position reported in future period.

Further details of the nature of these assumptions and conditions may be found in the relevant notes to the financial statements.

4. Significant accounting judgements, estimates and assumptions continued

Hydrocarbon reserve and resource estimates

Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from the Group's oil and gas properties. The Group estimates its commercial reserves and resources based on information compiled by appropriately-qualified persons relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates. Commercial reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices, the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the Production-Sharing Agreements. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs. The current long-term Brent oil price assumption used in the estimation of commercial reserves is USD 55/bbl. The carrying amount of oil and gas properties at 31 December 2019 is shown in Note 16.

The Group estimates and reports hydrocarbon reserves in line with the principles contained in the Society of Petroleum Engineers (SPE) Petroleum Resources Management Reporting System (PRMS) framework. As the economic assumptions used may change and as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Group's reported financial position and results, which include:

- The carrying value of oil and gas properties may be affected due to changes in estimated future cash flows (Note 16);
- Depreciation and amortisation charges in the statement of profit or loss and other comprehensive income may change where such charges are determined using the UOP method, or where the useful life of the related assets change (Note 16);
- Provisions for decommissioning may require revision — where changes to reserves estimates affect expectations about when such activities will occur and the associated cost of these activities (Note 20).

Taxes

The Group operates in several tax jurisdictions, and consequently, its income is subject to various rates and rules of taxation. As a result, the Company's effective tax rate may vary significantly depending upon the profitability of operations in the different jurisdictions.

The Group recognises the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction, to the extent that future cash flows and taxable income differ significantly from estimates. The ability of the Group to realise the net deferred tax assets recorded at the date of the statement of financial position could be impacted.

Additionally, future changes in tax laws in the jurisdictions in which the Group operates could limit the ability of the Group to obtain tax deductions in future periods.

Additional information on the accounting policy for taxes is explained further in Note 10.

Decommissioning costs

Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's facilities and properties. The Group assesses its retirement obligation at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing, extent and amount of expenditure can also change, for example in response to changes in reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning costs. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The provision at reporting date represents management's best estimate of the present value of the future decommissioning costs required.

Share-based payment – Costs of listing

The listed entity, PetroNor E&P Limited has not met the definition of a business for the reverse acquisition transaction, consequently no goodwill is allowed to be capitalised for the variance between the consideration paid and the fair value net assets on acquisition. Correspondingly, any excess-deemed acquisition costs must be accounted for as an expense in accordance with AASB 2 (Note 23a).

For most reverse takeover transactions of listed shell companies, there is minimal variance between the consideration paid and the fair value of the net assets acquired, and any associated share-based expense may not be significant.

Due to the ongoing arbitration matters in Senegal and The Gambia and the uncertainty over legal tenure, these exploration licences have no book value in the accounting records of the Company. This accounting treatment has meant there is a significant variance between the market value of the company as indicated by its publicly traded share price and the book net assets on completion of the transaction.

5. Revenue from contracts with customers

	2019 USD'000	2018 USD'000
Revenue from sales of petroleum products	**57,479**	54,687
Assignment of tax oil	**29,894**	31,124
Assignment of royalties	**15,387**	15,258
	102,760	101,069

Quantity of oil lifted (barrels)	**880,844**	812,000
Average selling price (USD per barrel)	**65.25**	67.35

All revenue from the sales of petroleum products is recognised and transferred at a point in time

6. Cost of sales

	2019 USD'000	2018 USD'000
Operating expenses	**18,292**	22,125
Royalty	**15,387**	15,258
Depreciation and amortisation of oil and gas properties	**3,231**	3,206
Closing oil inventory	**297**	988
	37,207	41,577

7. Other operating income

	2019 USD'000	2018 USD'000
Other	**9**	491

8. Administrative expenses

	Note	2019 USD'000	2018 USD'000
Employee benefit expenses		**4,035**	4,206
Travelling expenses		**1,047**	1,492
Business development expenses		**19**	1,794
Legal and professional expenses		**6.502**	1,651
Office rent		**214**	202
Related-party loan write-off	24	**5,305**	–
Other expenses		**2,671**	745
		19,793	10,090

8. Administrative expenses continued

8a. Employee benefit expenses

	2019 USD'000	2018 USD'000
Salaries	**3,331**	3,542
Short-term non-monetary benefits	**308**	347
Defined contribution pension cost	**75**	–
Share-based payment expense	**–**	–
Social-security contributions and similar taxes	**321**	317
	4,035	4,206

8b. Auditors' remuneration

	2019 USD'000	2018 USD'000
Paid or payable to BDO		
Audit review of financial reports		
BDO (WA) Pty Ltd	**40**	–
BDO related practices	**90**	–
	130	–
Other non-assurance services		
BDO related practices	**12**	–
	142	–
Paid or payable to other audit firms		
Audit or review of financial reports	**138**	125
Other non-assurance services	**141**	–
	279	125

Fees, excluding VAT, to the auditors are included in administration expenses.

9. Finance cost

	Note	2019 USD'000	2018 USD'000
Unwinding of discount on decommissioning liability	20	**877**	824
Loan structuring fee		**105**	100
Interest on loan	19	**839**	599
		1,822	1,623

10. Tax expense

	2019 USD'000	2018 USD'000
Petroleum revenue tax expense		
Current income tax charge	**29,894**	31,124
Total tax expense reported in the consolidated statement of comprehensive income	**29,894**	31,124

The income tax expense is only related to the subsidiary in Congo and represents the assignment of tax oil on the revenue from sales of petroleum products, Note 5. There was no income tax expense in the other subsidiaries' jurisdictions nor in the parent's jurisdiction as these companies are in taxable loss positions in both 2019 and 2018. Average effective tax rate for the year was 29% (2018: 31%) based on gross revenue of the Group.

Deferred tax assets have not been brought to account in respect of tax losses and unrecognised capital allowances because as at 31 December 2019 it is uncertain when future taxable amounts will be available to utilise those temporary differences and losses. As at 31 December 2019, the carried forward gross tax loss is USD 202 million (2018: USD 1.68 million).

11. Earnings per share

	2019 USD'000	2018 USD'000
(Loss) / Profit attributable to ordinary shareholders		
(Loss) / Profit from continuing operations attributable to the ordinary equity holders used in calculating basic loss per share	**(13,364)**	7,838
(Loss) / Profit attributable to the ordinary equity holders used in calculating basic loss per share	**(13,364)**	7,838

	Number of shares	Number of shares
Weighted average number of ordinary shares outstanding during the period used in the calculation of basic and diluted (loss) / profit per share	**1,140,087,271**	816,198,842

Options on issue are considered to be potential ordinary shares and have been included in the determination of diluted loss per share only to the extent to which they are dilutive. There are 3,266,470 options as at 31 December 2019 (2018: nil options). These options have not been included in the determination of basic loss per share because they are considered to be anti-dilutive.

12. Inventories

	2019 USD'000	2018 USD'000
Crude oil inventory	**871**	868
Materials and supplies	**2,362**	1,702
	3,233	2,570

The crude oil inventory and the material and supplies inventory are valued at the lower of cost and net realisable value. Cost is determined using the weighted average method. Net realisable value is the estimated selling price, less applicable selling expenses. The cost of inventory includes all costs related to bringing the inventory to its current condition, including processing costs, labour costs, supplies, direct and allocated indirect operating overhead and depreciation expense, where applicable, including allocation of fixed and variable costs to inventory.

13. Accounts receivable, deposits and prepayments

	Note	2019 USD'000	2018 USD'000
Trade receivables		**4,013**	3,391
Due from related parties	24	**5,639**	12,929
Advance against decommissioning cost[1]	20	**14,646**	11,360
Other receivables		**474**	530
		24,772	28,210

1. In addition to the booking of decommissioning cost asset and liability, the contractors group and the Congolese Government have decided to set up funds for the decommissioning cost in an escrow account which is managed by the operator. The advances of the funds for the year are made on the basis of an average rate of 3.50 USD per barrel produced (2018: 4.28 USD per barrel).

14. Cash and bank balances

	2019 USD'000	2018 USD'000
Cash in bank	**26,988**	7,924
Petty cash	**–**	2
Restricted cash	**903**	–
	27,891	7,926

Restricted cash balances represent cash-backed security provided in relation to the Company's obligations required under the exploration licences. The cash will be utilised for training and resources by mutual agreement with the relevant country's government authorities.

15. Segment information

For management purposes, the Group is organised into one main operating segment, which involves exploration and production of hydrocarbons. All of the Group's activities are interrelated, and discrete financial information is reported to Chief Operating Decision Maker as a single segment. Accordingly, all significant operating decisions are based upon analysis of the Group as one segment. The financial results from this segment are equivalent to the financial statements of the Group as a whole.

The Group only has one operating segment, being exploration and production of hydrocarbons.

The analysis of the location of non-current assets is as follows:

	2019 USD'000	2018 USD'000
Congo	**27,182**	18,145
The Gambia	**–**	–
Nigeria	**–**	–
Norway	**83**	–
Senegal	**2**	–
UK	**11**	–
	27,278	18,145

16. Production assets and equipment

2019	**Production assets and equipment USD'000**	**Motor vehicles USD'000**	**Total USD'000**
Cost			
At 1 January 2019	**16,455**	**9**	**16,464**
Additions	**12,375**	**–**	**12,375**
Disposals	**–**	**(9)**	**(9)**
At 31 December 2019	**28,830**	**–**	**28,830**
Depreciation			
At 1 January 2019	**3,875**	**9**	**3,884**
Charge for the year	**2,368**	**–**	**2,368**
Depreciation on disposals	**–**	**(9)**	**(9)**
At 31 December 2019	**6,243**	**–**	**6,243**
Net carrying amount			
At 31 December 2019	**22,587**	**–**	**22,587**

2018	Production assets and equipment USD'000	Motor vehicles USD'000	Total USD'000
Cost			
At 1 January 2018	12,425	9	12,434
Additions	4,030	–	4,030
At 31 December 2018	16,455	9	16,464
Depreciation			
At 1 January 2018	1,571	9	1,580
Charge for the year	2,304	–	2,304
At 31 December 2018	3,875	9	3,884
Net carrying amount			
At 31 December 2018	12,580	–	12,580

Production assets and equipment cost includes the following:

	Note	2019 USD'000	2018 USD'000
Decommissioning costs	20	**11,899**	11,899
Oil & gas CAPEX		**16,819**	4,556
		28,718	16,455

17. Intangible assets

Net carrying value	Note	2019 USD'000	2018 USD'000
Licences and approval	17i	**4,686**	5,549
Software	17ii	**5**	7
Goodwill		**–**	9
		4,691	5,565

i) Licences and approval

	2019 USD'000	2018 USD'000
Cost		
At 1 January	**7,382**	7,382
Addition	**–**	–
At 31 December	**7,382**	7,382
Accumulated amortisation and impairment		
At 1 January	**1,833**	931
Amortisation	**863**	902
Impairment	**–**	–
At 31 December	**2,696**	1,833
Net carrying value		
At 1 January	**5,549**	6,451
At 31 December	**4,686**	5,549

Licence overview and risk

The Group's exploration and production assets relate to the following licences:

Country	Licence	Carrying value as at 31 December 2019 / USD 000,000	Operator	Working Interest	Area km^2
Congo	PNGF Sud	**5.5**	Perenco	20%	482.28
Senegal	Rufisque Offshore Profond	**–**	African Petroleum Senegal Limited	90%	10,357
Senegal	Senegal Offshore Sud Profond	**–**	African Petroleum Senegal Limited	90%	5,439
The Gambia	A1	**–**	African Petroleum Gambia Limited	100%	1,296
The Gambia	A4	**–**	African Petroleum Gambia Limited	100%	1,376

Congo

In 2017, subsidiary company Hemla E&P Congo SA acquired interest in three development and production permits (Tchendo: 20%; Tchibouela: 20% and Tchibeli-Litanzi: 20%) which will respectively end in December 2037 for each of them with possible extension for 5 years. All these three licenses are called or named collectively “PNGF Sud”.

17. Intangible assets continued

Senegal

As at the date of this report, the Company's subsidiary African Petroleum Senegal Limited had registered a request for arbitration proceedings with the International Centre for the Settlement of Investment Disputes (ICSID) to protect its interests in the Senegal Offshore Sud Profond and Rufisque Offshore Profond blocks in Senegal (ICSID case ARB/18/24).

The Gambia

As at the date of this report, the Company's subsidiary African Petroleum Gambia Limited had initiated arbitration proceedings at the ICSID to protect its interests in the A1 and A4 licences in The Gambia (ICSID case ARB/17/38).

Reserves

The Group has adopted a policy of regional reserve reporting using external third-party companies to audit its work and certify reserves and resources. Reserve and contingent resource estimates comply with the definitions set by the Petroleum Resources Management System ("PRMS") issued by the Society of Petroleum Engineers ("SPE"), the American Association of Petroleum Geologists ("AAPG"), the World Petroleum Council ("WPC") and the Society of Petroleum Evaluation Engineers ("SPEE") in March 2007. The Group uses the services of AGR Petroleum Services AS for 3rd party verifications of its reserves.

The following is a summary of key results from the reserve reports (net of the Group's share):

Asset	1P reserves MMbbls	2P reserves MMbbls	3P reserves MMbbls
PNGF Sud	7.02	10.76	14.04

Definitions:

1P) Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

2P) Proved plus Probable Reserves

Probable Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

3P) Proved plus Probable plus Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Probable Reserves.

ii) Software

	2019 USD'000	2018 USD'000
Cost		
At 1 January	**7**	–
Addition	**–**	7
At 31 December	**7**	7
Accumulated amortisation and impairment		
At 1 January	**–**	–
Amortisation	**2**	–
Impairment	**–**	–
At 31 December	**2**	–
Net carrying value		
At 1 January	**7**	–
At 31 December	**5**	7

18. Accounts payable and accrued liabilities

	Note	2019 USD'000	2018 USD'000
Trade payables		**14,809**	3,787
Due to related parties	24	**13,784**	2,138
Taxes and state payables		**473**	313
Other payables and accrued liabilities		**5,536**	3,415
		34,602	9,653

19. Loans payable

	2019 USD'000	2018 USD'000
At 1 January	**7,083**	–
Received	**12,917**	10,000
Principal repayment	**(7,059)**	(2,917)
Interest on loan accrued	**822**	699
Interest on loan paid	**(822)**	(699)
At 31 December	**12,941**	7,083

Ageing of loans payable	2019 USD'000	2018 USD'000
Current	**12,941**	5,000
Non-current	**–**	2,083
	12,941	7,083

During the year, the company renegotiated the terms of an existing loan from a third party Rasmala (Dubai-based investor group). The loan is repaid in monthly instalments and carries an interest rate of 10% plus one-month LIBOR payable monthly. The loan is secured against the assignment of receivables by subsidiary company Hemla Africa Holding AS and a corporate guarantee from significant shareholder Petromal – Sole Proprietorship LLC.

20. Decommissioning liability

In accordance with the agreements and legislation, the wellheads, production assets, pipelines and other installations may have to be dismantled and removed from oil and natural gas fields when the production ceases. The exact timing of the obligations is uncertain and depends on the rate the reserves of the field are depleted. However, based on the existing production profile of the PNGF Sud field and the size of the reserves, it is expected that expenditure on retirement is likely to be after more than ten years. The current bases for the provision are a discount rate of 6.5% and an inflation rate of 1.6%. The decommissioning liability (ARO) study was done internally by the operator Perenco and was presented to ARO Committee. The partners approved the study on 13 November, 2018.

The following table presents a reconciliation of the beginning and ending aggregate amounts of the obligations associated with the retirement of oil and natural gas properties:

	2019 USD'000	2018 USD'000
At 1 January	**13,496**	12,672
Arising during the year	**–**	–
Unwinding of discount on decommissioning	**877**	824
At 31 December	**14,373**	13,496

21. Share capital

Ordinary shares participate in dividends and the proceeds on winding up of the Company in proportion to the number of shares held and in proportion to the amount paid up on the shares held.

At shareholders' meetings, each ordinary share entitles the holder to one vote in proportion to the paid-up amount of the share when a poll is called, otherwise each shareholder has one vote on a show of hands.

Reconciliation of movement in shares on issue

	Number of fully paid ordinary shares 2019
Balance of shares of Cypriot PetroNor E&P Ltd prior to merger	**100,000**
Balance of shares of Australian PetroNor E&P Limited prior to merger	**155,466,446**
Acquisition of Cypriot PetroNor E&P Ltd shares	**(100,000)**
Issue of shares for merger consideration[1]	**816,198,842**
Exercise of share options and warrants	**–**
Balance at end of the year	**971,665,288**

1. On 30 August 2019, the Company issued 816,199,842 shares at NOK 1.032 each

Cypriot company, PetroNor E&P Ltd had 100,000 ordinary shares as at the beginning and end of 2018, with no movements during the year.

Reconciliation of movements in issued capital

	2019 USD'000	2018 USD'000
Balance at beginning of the year		
Fair value of issued share capital at beginning of the year	**120**	120
Issue of shares for reverse takeover[1]	**17,615**	–
Exercise of share options	**–**	–
Share capital at end of the year	**17,735**	120

1. On 30 August 2019, the Company issued 816,199,842 shares at NOK 1.032 each

Capital Management

Management controls the capital of the Company in order to maximise the return to shareholders and ensure that the Company can fund its operations and continue as a going concern. Capital is defined as issued share capital.

Management effectively manages the Company's capital by assessing the Company's financial risks and adjusting its capital structure in response to changes in these risks and in the market. These responses include the management of expenditure and debt levels, distributions to shareholders and share and option issues. There have been no changes in the strategy adopted by management to control the capital of the Company since the prior reporting period.

Management monitors capital requirements through cash flow forecasting. Management may seek further capital if required through the issue of capital or changes in the capital structure. The Group has no externally imposed capital requirements.

22. Reserves

Share-based payment reserve

The share-based payments reserve records options and share awards recognised as expenses, issued to employees, directors and consultants.

Foreign currency translation reserve

The foreign currency translation reserve is used to recognise foreign currency exchange differences arising on translation of functional currency to presentation currency.

Retained earnings

All other net gains and losses and transactions with owners not recognised elsewhere.

23. Share-based payments

	2019 USD'000	2018 USD'000
Reverse acquisition – Costs of listing	**19,374**	–
Warrants	**–**	–
Options	**–**	–
Share based payment charge for the year	**19,374**	–

23a. Reverse acquisition – costs of listing

On 30 August 2019, the Company entered into a share purchase agreement with the Cypriot company PetroNor E&P Ltd. Consideration for 100% of the share capital of the Cypriot company comprised the following:

- 816,198,842 new shares issued at NOK 1.032 each;
- 155,466,446 warrants issued with a nil exercise price, vesting conditions and expiry date of 31 December 2019. The vesting conditions related to specific performance milestones including the signing of a binding gas offtake agreement for an asset in Nigeria; and
- USD 11,549,988 deferred cash consideration, payable and due upon the finalisation of the 2018 dividend from the operating subsidiary company Hemla E&P Congo SA.

Costs associated with the transaction totalled USD 2 million; and has been expensed as incurred by both sides. Therefore, only costs of USD 1.19M are included in the Statement of Comprehensive Income for the transaction, with the balance recognised as part of the retained losses of Australian PetroNor E&P Limited at the point of the merger.

The transaction has been considered a reverse takeover, but not a business combination. Although the Australian company PetroNor E&P Limited has licences in The Gambia and Senegal, with the ongoing arbitration matters there were no active operations, consequently the Company was considered a 'non-business' listed company.

The Cypriot company PetroNor E&P Ltd is considered the accounting acquirer and the Australian company PetroNor E&P Limited is the legal acquirer.

The acquisition is accounted for as a continuation of the financial statements of the Cypriot PetroNor E&P Ltd. The Transaction assessed fair value in excess of the net assets of Australian PetroNor E&P Limited, and an estimate for listing expenses has been expensed as a share-based payment in accordance with AASB 2.

The estimate for listing expenses is based on the deemed market capitalisation of the company:

		Number of shares[1]	Share value USD'000
Existing Australia PetroNor E&P Limited shareholders	16%	155,466,446	17,615
New issue to Cypriot PetroNor E&P Ltd shareholders	84%	816,198,842	92,479
Deemed market capitalisation of the Company	100%	971,665,288	98,544

1. Share price on completion date 30 August 2019, NOK 1.032 (equivalent USD 0.113)

	USD' 000
Implied issued capital for acquisition of Australian PetroNor E&P Limited	17,615
Add net book value of Australian PetroNor E&P Limited net liabilities acquired as at 30 August 2019	1,759
Share-based payment charge for the year	19,374

Accounting treatment of exploration assets only allows intangible asset values to be carried forward and not impaired, if the Company can demonstrate legal right of tenure. Due to the ongoing arbitration matters for the Senegalese and Gambian licences, there was uncertainty around the legal right of tenure for these licences. For this reason, the book carrying value of these assets is nil for the transaction. However, prior to completion of the reverse acquisition transaction the market capitalisation of Australian company PetroNor E&P Limited exceeded the book value of its net liabilities, therefore implying the Senegalese and Gambian licences had significant residual value, and supports the material share-based payment charge recognised for the transaction.

23. Share-based payments continued

23b. Warrants

During the current year, 8,513,848 unlisted warrants were issued to staff, Directors and consultants of the Company; these were subject to vesting conditions dependent on operational performance milestones related to the reinstatement of licences in The Gambia and Senegal.

During the current year, 310,932,892 unlisted warrants were issued to shareholders of the Company, these were subject to vesting conditions dependent on operational performance milestones either related to the reinstatement of licences in The Gambia and Senegal, or the signing of a binding gas offtake agreement for an asset in Nigeria.

None of these warrants vested before the expiry date of 31 December 2019, and consequently as at the year-end, there were no unlisted warrants outstanding (31 December 2018: nil). No expense was recognised within the Statement of Comprehensive Income for the issue of these warrants, as the warrants were subject to vesting conditions that did not occur; and were awarded and lapsed during the same period.

Grant date	Expiry date	Number of options	Expected life of options (years)	Risk free rate (%)	Volatility (%)	Dividend yield (%)	Exercise price NOK	Exercise price equivalent USD	Fair value at grant date NOK	Fair value at grant date USD
30 Aug 2019	31 Dec 2019	319,446,740	0.33	0.89	125	–	nil	nil	1.032	0.113

23c. Options

Holders of options do not have any voting or dividend rights in relation to the options.

The Company has used the Black-Scholes methodology for measuring the option pricing.

The following reconciles the outstanding share options granted, exercised and forfeited during the year:

	2019		2018	
	Number of options	**Weighted average exercise price equivalent USD[1]**	Number of options[1]	Weighted average exercise price equivalent USD[1]
Balance at beginning of the period	**–**	**–**	–	–
Awarded	**–**	**–**	–	–
Reverse takeover[2]	**3,283,137**	**0.53**	–	–
Lapsed	**(16,667)**	**2.10**	–	–
Forfeited during the year	**–**	**–**	–	–
Balance at end of the year	**3,266,470**	**0.53**	–	–
Exercisable at end of the year	**3,266,470**	**0.53**	–	–

1. The USD equivalent weighted average exercise price as at 31 December 2019
2. On August 2019, 3,283,137 options were recognised in relation to outstanding options awarded before the reverse acquisition transaction with PetroNor E&P Limited took place.

The value of options capitalised during the period was nil (2018: nil).

The share options outstanding at the end of the period had a weighted average remaining contractual life of 495 days (2018: nil days).

24. Related party transactions

24a. Subsidiaries

The principal subsidiaries of the PetroNor E&P Limited group, all of which have been included in these consolidated financial statements, are as follows:

Name	Country of incorporation	Principal place of business	Proportion of ownership interest at 31 December 2019	2018
PetroNor E&P Ltd	Cyprus	Cyprus	**100%**	100%
PetroNor E&P AS	Norway	Norway	**100%**	100%
PetroNor E&P Services Ltd[1]	United Kingdom	United Kingdom	**100%**	–
PetroNor E&P Nigeria Ltd	Nigeria	Nigeria	**100%**	–
Hemla Africa Holding AS	Norway	Norway	**70.707%**	70.707%
Hemla E&P Congo SA	Congo	Congo	**52.50%**	52.50%
African Petroleum Corporation Ltd[1]	Cayman Islands	United Kingdom	**100%**	–
African Petroleum Gambia Ltd[1]	Cayman Islands	The Gambia	**100%**	–
African Petroleum Senegal Ltd[1]	Cayman Islands	Senegal	**90%**	–
African Petroleum Senegal SAU[1]	Senegal	Senegal	**100%**	–
APCL Gambia BV [1]	Netherlands	The Gambia	**100%**	–

1. These entities merged into the group on the completion of the reverse takeover of African Petroleum Corporation Limited on 30 August 2019

Reverse takeover

On 30 August 2019, the Oslo Axess listed company PetroNor E&P Limited ("PNOR") (formerly called African Petroleum Corporation Limited) purchased the entire share capital of PetroNor E&P Ltd, a company registered in Cyprus. The consideration for the transaction comprised of the issue of 816,198,842 ordinary shares in PNOR, the issue of 155,466,446 warrants contingent on performance milestones in PNOR, and the deferred cash consideration of USD 11,549,988 to represent the share of the dividend payable for the year ended 31 December 2018 from operating subsidiary, Hemla E&P Congo SA.

Material non-controlling interests

	2019		2018	
	Hemla E&P Congo SA USD'000	**Hemla Africa Holding AS USD'000**	Hemla E&P Congo SA USD'000	Hemla Africa Holding AS USD'000
Non-current assets	**28,959**	**1,185**	18,135	1,188
Current assets	**38,106**	**26,291**	28,147	24,680
Non-current liabilities	**14,373**	**–**	13,496	2,083
Current liabilities	**20,911**	**13,092**	7,845	19,347
Revenue	**102,760**	**–**	101,069	59,496
Profit for the year	**27,430**	**9,950**	20,652	4,461
Total comprehensive income for the year	**27,430**	**9,950**	20,652	4,461
Profit attributable to non-controlling interest	**13,029**	**2,915**	9,810	1,307
Dividends distributed during the year	**22,000**	**–**	8,500	–

24b. Key management personnel remuneration

Key management personnel are those persons having authority and responsibility for planning, directing and controlling the activities of the Group, including the directors of the company listed on page 24, and the following other key personnel:

G Ludvigsen	Business Development Manager
C Frimann-Dahl	Chief Technical Officer
E Sultan	Strategy and Contracts Manager
M Barrett	Exploration Manager
C Butler	Group Financial Controller
A Hicks	Company Secretary

24. Related party transactions continued

Post year-end remuneration reductions

Following the restructure of the Board of Directors after the merger of the companies and also in response to the Covid-19 global pandemic, remuneration for key management was reconsidered to lower the cost base and strengthen the position of the Company during this crisis. As at the approval date of this report the reduced base salary and fees for the following members of key management is as follows:

Individual	Title	Group Entity	Salary and fees/ per annum	Total salary and fees USD equivalent USD
E Alhomouz	Chairman[1]	PetroNor E&P AS	USD 240,000	360,000
	Non-Executive Director	Hemla E&P Congo SA	USD 120,000	
K Søvold	Exec Director & CEO	PetroNor E&P AS	NOK 1,860,000	240,790
	Non-Executive Director	Hemla E&P Congo SA	USD 60,000	
G Ludvigsen	Business Development Manager	PetroNor E&P AS	NOK 1,860,000	240,790
	Non-Executive Director	Hemla E&P Congo SA	USD 60,000	
E Sultan	Strategy & Contracts Manager[1]	PetroNor E&P AS	USD 120,000	120,000
C Frimann-Dahl	Chief Technical Officer	PetroNor E&P AS	NOK 1,500,000	145,800
M Barrett	Exploration Manager	PetroNor E&P Services Ltd	GBP 150,000	186,000
C Butler	Group Financial Controller	PetroNor E&P Services Ltd	GBP 115,000	142,600

1. Fees are charged by related party Petromal LLC and are not paid to the individual; above figures represent the company's fair value estimate of associated costs for the individual's services

FX rates used as at 9th April	NOK 1.00 : USD 0.0972	GBP 1.00 : USD 1.24

The rates of other cash benefits and post-employment benefits were unchanged.

When former Executive Officers, Jens Pace and Stephen West resigned these roles on 29 February 2020, the termination benefit equivalent to one year's salary was agreed to be paid out in equal monthly instalments over an 18- and 12-month period respectively.

Remuneration of key management personnel

2019	Designation	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Total USD
Management					
K Søvold	Exec Director & COO	**358,551**	**1,989**	**24,350**	**384,891**
J Pace[1]	Exec Director & CEO	**159,716**	**2,076**	**–**	**161,792**
S West[1]	Exec Director & CFO	**113,257**	**1,034**	**11,326**	**125,617**
G Ludvigsen	Business Development Manager	**360,119**	**466**	**25,829**	**386,414**
C Frimann-Dahl	Chief Technical Officer	**226,678**	**–**	**–**	**226,678**
M Barrett[1]	Exploration Manager	**125,491**	**506**	**–**	**125,617**
C Butler[1]	Group Financial Controller	**48,239**	**2,209**	**4,824**	**55,272**
E Alhomouz	Related party fees[2]	**361,488**	**–**	**–**	**361,488**
E Sultan	Related party fees[2]	**301,239**	**–**	**–**	**301,239**
A Hicks[1]	Company Secretary	**5,466**	**–**	**–**	**5,466**
		2,060,245	**8,280**	**66,329**	**2,134,854**
Directors' remuneration for PetroNor E&P Ltd Australia					
J Iskander[3]	Non-Exec Director	**–**	**–**	**–**	**–**
D King[1]	Non-Exec Director	**12,000**	**–**	**–**	**12,000**
B Moe[1]	Non-Exec Director	**11,000**	**–**	**–**	**11,000**
T Turner[1]	Non-Exec Director	**5,456**	**–**	**–**	**5,456**
		28,456			**28,456**
Directors' remuneration for subsidiaries					
E Alhomouz	Non-Exec for HEPCO	**120,000**	**120,000**		**120,000**
K Søvold	Non-Exec for HEPCO	**66,000**	**66,000**		**66,000**
G Ludvigsen	Non-Exec for HEPCO	**66,000**	**66,000**		**66,000**
A Georghiou[4,5]	Non-Exec for PetroNor E&P Ltd	**6,143**	**–**	**–**	**6,143**
H Marshad[5]	Non-Exec for PetroNor E&P Ltd	**5,500**	**–**	**–**	**5,500**
N Kouyialis[4,5]	Non-Exec for PetroNor E&P Ltd	**6,250**	**–**	**–**	**6,250**
		269,893	**–**	**–**	**269,893**

1. Table only includes post-completion remuneration to former Australian company PetroNor E&P Limited key management personnel, i.e. from 30 August 2019
2. Remuneration is not paid to the individual, as fees are included in a monthly lump sum charged by related party Petromal LLC, above figures represent the company's fair value estimate of associated costs for the individual's services.
3. Mr Iskander was appointed on 30 August 2019, and agreed to waive his remuneration
4. Appointed 17 April 2019
5. Individual ceased to be part of key management, upon completion of reverse acquisition of Australian company PetroNor E&P Limited on 30 August 2019

2018[1]	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Total USD
Management				
K Søvold	98,479	–	–	98,479
G Ludvigsen	100,270	–	–	100,270
E Alhomouz[2]	100,000	–	–	100,000
	299,018	–	–	299,018
Directors' remuneration for subsidiaries				
K Søvold	66,000	–	–	66,000
G Ludvigsen	60,500	–	–	60,500
E Alhomouz	106,500	–	–	106,500
	233,000	–	–	233,000

1. Comparative table represents remuneration of key management of consolidated group of PetroNor E&P Ltd, registered in Cyprus.
2. Remuneration is not paid to the individual, as fees charged by related party Petromal LLC; above figures represent the company's fair value estimate of associated costs for the individual's services.

During 2019, Employer's social taxes of USD 169,118 (2018: USD 28,062) were payable for the key management remuneration.

24. Related party transactions continued

Pro-forma remuneration for members of key management personnel from Australian company PetroNor E&P Limited, assuming the reverse acquisition had taken place on 1 January 2019:

2019	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Share-based payments – options USD	Total USD
J Pace	485,444	7,585	–	–	493,209
S West	344,236	5,407	34,424	–	384,067
M Barrett	381,420	2,066	–	–	383,487
C Butler	146,619	5,115	14,662	–	166,396
D King	20,000	–	–	–	20,000
B Moe	19,000	–	–	–	19,000
T Turner	11,056	–	–	–	11,056
A Hicks	16,674	–	–	–	16,674
Total	1,424,540	20,174	49,086	–	1,493,889

Share holdings by Directors and other Key Management Personnel

	Balance 1 January 2019	Reverse acquisition net change	Shares purchased	Granted as remuneration	Net change other	Balance 31 December 2019
J Pace	–	1,498,938	–	–	–	1,498,938
S West	–	1,377,554	–	–	–	1,377,554
M Barrett	–	1,151,667	–	–	–	1,151,667
C Butler	–	234,296	–	–	–	234,296
C Frimann-Dahl	–	–	50,000	–	–	50,000
D King	–	30,000	–	–	–	30,000
B Moe	–	10,000	–	–	(10,000)	–
T Turner	–	4,167	–	–	–	4,167
	–	4,356,622	–	–	(10,000)	4,346,622

As at 31 December 2019, Eyas Alhomouz held no shares personally, but holds influence over 371,961,246 shares (2018: 50,000 shares) as the CEO of significant shareholder Petromal LLC.

As at 31 December 2019, 444,237,596 shares (2018: 50,000 shares) are held by NOR Energy AS, a company controlled jointly by Knut Søvold and Gerhard Ludvigsen through an indirect beneficial interest.

Other members of key management not included in the above table held no shares during the current year.

Warrant and option holdings by Directors and other Key Management Personnel

	Balance 1 January 2019	Reverse acquisition net change	Awarded as remuneration	Options exercised	Net change other	Balance 31 December 2019	Exercisable	Not Exercisable
J Pace	–	3,919,710	–	–	(3,919,710)	–	–	–
S West	–	3,761,902	–	–	(3,761,902)	–	–	–
M Barrett	–	2,712,424	–	–	(2,712,424)	–	–	–
C Butler	–	709,686	–	–	(709,686)	–	–	–
D King	–	615,536	–	–	(615,536)	–	–	–
B Moe	–	346,809	–	–	(346,809)	–	–	–
T Turner	–	238,382	–	–	(238,382)	–	–	–
A Hicks	–	62,753	–	–	(62,753)	–	–	–
	–	12,367,202	–	–	12,367,202	–	–	–

Members of key management not included in the above table held no warrants or options during the current year

24c. Significant Shareholders

Shareholder	Place of incorporation	31 December 2019 Ownership	31 December 2018 Ownership
Nor Energy AS	Norway	**46%**	50%
Petromal LLC – Sole Proprietorship LLC	UAE	**38%**	50%

24d. Transactions and period-end balances with related parties

Transactions with related parties included in the consolidated statement of comprehensive income:

	2019 USD'000	2018 USD'000
Nor Energy AS	**–**	753
Petromal – Sole Proprietorship LLC	**–**	1,582
Cost of sales	**–**	2,335
Nor Energy AS subsidiary company – loan write-off[1]	**5,305**	–
Nor Energy AS – charge back of expenses	**103**	1,000
Petromal – Sole Proprietorship LLC	**1,088**	–
Administrative expenses	**6,496**	1,000

Balances due from and due to related parties disclosed in the consolidated statement of financial position:

	2019 USD'000	2018 USD'000
Loan receivable from MGI International S.A.[2]	**5,639**	7,000
Loan receivable from Nor Energy AS subsidiary company[1]	**–**	5,700
Other receivable from Nor Energy AS	**–**	229
Total receivables from related parties (Note 13)	**5,639**	12,929
Other payable to Nor Energy AS	**5,783**	975
Other payable to Petromal – Sole Proprietorship LLC	**4,534**	1,163
Other payable to MGI International S.A.	**3,467**	–
Total payables to related parties (Note 18)	**13,784**	2,138

1 During 2017, Hemla Africa Holding AS provided a loan facility of USD 6 million to a Nor Energy AS subsidiary company, for which the borrower had an option to drawdown in one or more instalments. The loan did not carry any interest and was repayable on demand. However, prior to the merger on 30 August 2019, the outstanding balance of USD 5.3 million was written off to administrative expenses.
2 During the prior year, Hemla Africa Holding AS (HAH AS) provided a loan of USD 7 million to MGI International SA, (minority shareholder in Hemla E&P Congo SA (HEPCO). The loan will be repaid directly by HEPCO to HAH AS from its yearly dividends being 25% of MGI's share of dividend in the first year and 40% thereafter. The loan does not carry any interest unless there is a breach of any clause of the loan agreement in which case 4% p.a. will be accrued on the outstanding amount of loan.

Amounts due from/to related parties included in the consolidated statement of financial position (other than the loans to related parties) are interest-free and have no fixed repayment terms.

25. Risk Management

The Group's principal financial liabilities comprise accounts payable and amounts due to related parties. The main purpose of these financial instruments is to manage short-term cash flow and raise finance for the Group's capital expenditure programme. The Group has various financial assets such as accounts receivable and cash.

It is, and has been throughout the year ending 31 December 2019, the Group's policy that no speculative trading in derivatives shall be undertaken.

The main risks that could adversely affect the Group's financial assets, liabilities or future cash flows are credit risk, liquidity risk, interest rate risk and foreign currency risk. The management reviews and agrees policies for managing each of these risks which are summarized below.

The following discussion also includes a sensitivity analysis that is intended to illustrate the sensitivity to changes in the market variables on the Group's financial instruments and shows the impact on profit or loss and shareholders' equity, where applicable. Financial instruments affected by market risk include, accounts receivable, accounts payable and accrued liabilities.

25. Risk Management continued

The sensitivity has been prepared for periods ending 31 December 2019 using the amounts of debt and other financial assets and liabilities held as at those reporting dates.

Credit risk

Credit risk is the risk that one party to a financial instrument will fail to discharge an obligation and cause the other party to incur a financial loss.

The Group seeks to limit its credit risk with respect to banks by only dealing with reputable banks and with respect to customers by setting credit limits for individual customers and monitoring outstanding receivables. However, management is confident that this concentration of credit risk will not result in any loss to the Group due to the strong business relationship with and good reputation of the customers.

With respect to credit risk arising from the other financial assets of the Group, including cash and cash equivalents, the Group's exposure to credit risk arises from default of the counterparty, with a maximum exposure equal to the carrying amount of these instruments.

Liquidity risk

The Group seeks to limit its liquidity risk by ensuring financial support is available from the shareholders. The Group's terms of sales requires amounts to be paid within 45 to 60 days of the date of approval of progress billings. Trade payables are normally settled within 90 to 120 days of the date of receipt of invoice.

The table below summarises the maturity profile of the Group's financial liabilities at 31 December 2019 based on contractual undiscounted payments.

USD'000	Note	On demand	Less than 1 month	Between 1 and 3 months	Between 3 months and 1 year	More than 1 year	Total
31 December 2019							
Trade accounts payable	**18**	**616**	**1,580**	**2,483**	**10,130**	**–**	**14,809**
Amounts due to related parties	**24d**	**13,784**	**–**	**–**	**–**	**–**	**13,784**
Loan payable[1]	**19**	**–**	**588**	**1,176**	**11,176**	**–**	**12,941**
		14,400	**2,168**	**3,659**	**21,306**	**–**	**41,535**

USD'000	Note	On demand	Less than 1 month	Between 1 and 3 months	Between 3 months and 1 year	More than 1 year	Total
31 December 2018							
Trade accounts payable	18	–	3,787	–	–	–	3,787
Amounts due to related parties	24d	–	–	2,138	–	–	2,138
Loan payable	19	–	696	2,036	5,177	3,028	10,937
		–	4,483	4,174	5,177	3,028	16,862

1. Post year-end in April 2020, the loan was replaced with a USD 15 million facility with 12 months' grace period and final maturity date in October 2022.

The Company had USD 27.0 million (2018: 7.9 million) in unrestricted cash as of 31 December 2019. Should additional funding be required in the future for additional capital expenditure for new development phases or working capital requirements, the Company has various alternatives available which it can explore to fulfil such additional requirements. The options include, amongst others, debt financing, offtake prepayment structures. As a result, the financial statements have been prepared under the assumption of going concern and realisation of assets and settlement of debt in normal operations.

Interest rate risk

The Group is exposed to interest rate risk on its interest-bearing assets and liabilities and seeks to limit this risk by obtaining favourable interest rates.

	31 December 2019		31 December 2018	
	+150bp USD'000	**–150bp USD'000**	+150bp USD'000	–150bp USD'000
Loans payable	**(194)**	**194**	(106)	106

Currency risk

The Group operates internationally and is exposed to risk arising from various currency exposures, primarily with respect to the Norwegian Kroner (NOK) and the Great British Pound (GBP). The Group has transactional currency exposures. Such exposure arises from sales or purchases in currencies other than the respective functional currency.

The Group reports its consolidated results in USD; any change in exchange rates between its operating subsidiaries' functional currencies and the USD affects its consolidated statement of comprehensive income and statement of financial position when the results of those operating subsidiaries are translated into USD for reporting purposes.

Group companies are required to manage their foreign exchange risk against their functional currency.

A 20% strengthening or weakening of the USD against the following currencies at 31 December 2019 would have increased/(decreased) equity and profit or loss by the amounts shown below.

The Group's assessment of what a reasonable potential change in foreign currencies that it is currently exposed to have been changed as a result of the changes observed in the world financial markets. This hypothetical analysis assumes that all other variables, including interest rates and commodity prices, remain constant.

	31 December 2019		31 December 2018	
	+20% USD'000	**–20% USD'000**	+20% USD'000	–20% USD'000
USD vs NOK				
Cash	**45**	**(45)**	81	(81)
Receivables	**99**	**(99)**	678	(678)
Payables	**(246)**	**246**	(17)	17
	(102)	**102**	742	(742)
USD vs GBP				
Cash	**3**	**(3)**	–	–
Receivables	**11**	**(11)**	–	–
Payables	**(119)**	**119**	–	–
	(105)	**105**	–	–

Capital risk

The primary objective of the Group's capital management is to continuously evaluate measures to strengthen its financial basis and to ensure that the Group is fully funded for its committed 2020 activities. The Group manages its capital structure and makes adjustments to it in light of changes in economic conditions. In order to maintain or change the capital structure, the Group may adjust the amount of dividend payments to shareholders, return capital to shareholders or issue new shares. The Group has no significant debt arrangements in place and has the flexibility to source conventional debt capital from the markets.

The Group is continuously evaluating the capital structure, with the aim of having an optimal mix of equity and debt capital to reduce the Group's cost of capital, and looking at avenues to procure capital in the forthcoming year.

26. Financial instruments – Fair values

Financial instruments comprise financial assets and financial liabilities.

Financial assets consist of bank balances and cash, amounts due from related parties and trade and some other receivables. Financial liabilities consist of amounts due to related parties, loan payables, trade account payables and some other liabilities.

The fair values of the Group's financial instruments are not materially different from their carrying amounts at the reporting date largely due to the short-term maturities of these instruments.

27. Commitments and contingencies

Commitments

Exploration commitments

The Company has entered into obligations in respect of its exploration projects. Outlined below are the minimum expenditures required as at 31 December:

	2019 USD'000	2018 USD'000
Within one year[1]	**40,000**	–

1 The commitment in Senegal includes USD 40m for an exploration well in each licence, however this assumes that the Company is successful in retaining the legal title for these licences and that the Company then drills these wells with 90% equity.

Office rental commitments

The Company has entered into obligations in respect of office premises. Commitments for the payment of office rental in existence at the reporting date but not recognised as liabilities are as follows:

	2019 USD'000	2018 USD'000
Within one year	**188**	–
More than 1 year, less than 3 years	**201**	–
Total	**389**	–

28. Parent entity financial information

i. Summary financial information

The individual financial statements of the parent entity show the following aggregate amounts:

	2019 USD'000	2018 USD'000
Statement of financial position		
Current assets	**16,403**	42
Non-current assets	**104,027**	14,622
Total assets	**120,430**	14,664
Current liabilities	**(15,559)**	(246)
Total liabilities	**(15,559)**	(246)
Net Assets	**104,871**	14,418
Shareholders' equity		
Issued capital	**1,130,901**	1,039,121
Reserves	**29,391**	(6,192)
Accumulated losses	**(1,055,421)**	(1,018,511)
	104,871	14,418
Net loss for the year	**(1,357)**	(1,567)
Total comprehensive loss	**(1,357)**	(1,567)

ii. Guarantees entered into by the parent entity

As at 31 December 2019, the parent entity has not provided any financial guarantees in respect of bank overdrafts, decommissioning liabilities and loans of subsidiaries (31 December 2018: nil).

29. Events subsequent to reporting date

Board restructure

On 29 February 2020, Jens Pace stepped down as Chief Executive Officer, but remained on the Board as a Non-Executive Director. COO, Knut Søvold was immediately appointed the Chief Executive Officer. Also, on 29 February 2020, Stephen West resigned as the Chief Financial Officer and Executive Director.

Non-Executive Directors David King and Tim Turner resigned during February 2020; and were replaced by Alexander Neuling and Roger Steinepreis in April 2020.

COVID-19

Since the end of the financial year, the COVID-19 outbreak is a globally significant event impacting the health of individuals, international trade and commerce and, as a result, had a severely negative impact on global financial markets. The COVID-19 outbreak combined with the dramatic oil price decline has had a significant impact on the short-term oil prices. Consequently, this has adversely affected the Group’s business.

The Company has initiated an immediate cost reduction in the Company overhead and general administration cost. The key management salaries have been reduced with immediate effect from mid-March 2019. A full review of the Company expenditures has been completed and cost reduction actions are being implemented on a continuous basis. It has been important for management to ensure that the cost savings initiatives have limited impact on the capabilities of the company to continue its growth strategy even under these difficult circumstances and the new venture strategy of the company. The implemented initiatives will reduce the “normal budget” for 12 months forward from USD 14.1 million to USD 10.5 million. This number excludes any ongoing commitments such as redundancy packages and other costs which will be tapered down going forward.

Arbitration

On 4 May 2020, the arbitration proceedings for the Group’s interests in Senegal were suspended until 2 November 2020, following a mutual agreement between the parties.

Directors' declaration and statement of responsibility

We confirm that in the opinion of the Directors:

a) the financial statements and notes of PetroNor E&P Limited for the year ended 31 December 2019 are in accordance with the Corporations Act 2001, including:
   i. giving a true and fair view of its financial position as at 31 December 2019 and of its performance for the year ended on that date; and
   ii. complying with Australian Accounting Standards (including the Australian Accounting Interpretations) and the Corporations Regulations 2001; and
   iii. complying with International Financial Reporting Standards as disclosed in Note 2.

b) subject to the achievement of matters disclosed in Note 2 (Going Concern), there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

c) that the Directors' Report together with the Unaudited Additional Information includes a fair review of the development and performance of the business and the position of PetroNor E&P Limited and the Group taken as a whole, together with a description of the principal risks and uncertainties that they face; and

d) to the best of our knowledge, the country-by-country report for 2019 has been prepared in accordance with the Norwegian Security Trading Act Section 5-5a.

The Directors have been given the declarations required by Section 295A of the Corporations Act 2001 from the Chief Executive Officer, Knut Søvold, and the Group Financial Controller, Chris Butler, for the year ended 31 December 2019.

6 May 2020

The Board of Directors
PetroNor E&P Ltd

Eyas Alhomouz,
Chairman of the Board

Knut Søvold,
CEO and Executive Director of the Board

Jens Pace,
Director of the Board

Alexander Neuling,
Director of the Board

Joseph Iskander,
Director of the Board

Roger Steinepreis,
Director of the Board

Independent Auditor's Report
to the members of PetroNor E&P Limited

Report on the Audit of the Financial Report

Opinion

We have audited the financial report of PetroNor E&P Limited (the Company) and its subsidiaries (the Group), which comprises the consolidated statement of financial position as at 31 December 2019, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the year then ended, and notes to the financial report, including a summary of significant accounting policies and the directors' declaration.

In our opinion the accompanying financial report of the Group, is in accordance with the *Corporations Act 2001*, including:

i. Giving a true and fair view of the Group's financial position as at 31 December 2019 and of its financial performance for the year ended on that date; and

ii. Complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the Financial Report* section of our report. We are independent of the Group in accordance with the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the Financial Report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We confirm that the independence declaration required by the *Corporations Act 2001*, which has been given to the Directors of the Company, would be in the same terms if given to the Directors as at the time of this auditor's report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Material uncertainty related to going concern

We draw attention to Note 2 in the financial report which describes the events and/or conditions which give rise to the existence of a material uncertainty that may cast significant doubt about the Group's ability to continue as a going concern and therefore the Group may be unable to realise its assets and discharge its liabilities in the normal course of business. Our opinion is not modified in respect of this matter.

Other matter

The financial report of PetroNor E&P Ltd, for the year ended 31 December 2018 was audited by another auditor who expressed an unmodified opinion on that report on 29 July 2019.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the Financial Report of the current period. These matters were addressed in the context of our audit of the Financial Report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. In addition to the matter described in the *Material uncertainty related to going concern* section, we have determined the matters described below to be the key audit matters to be communicated in our report.

Accounting for the reverse acquisition accounting transaction

Key audit matter	How the matter was addressed in our audit
During the year ended 31 December 2019, African Petroleum Corporation Limited acquired 100% interest in the shares of PetroNor E&P Ltd on 30 August 2019, as disclosed in Note 23a to the financial report. The Group treated the transaction as a reverse asset acquisition, rather than a business combination, as disclosed in Note 4 and Note 23a of the financial report. Accounting for these transactions is complex and requires management to exercise judgement to determine the appropriate accounting treatment, including whether the acquisitions should be accounted for as asset acquisitions or business combinations, estimating the fair value of net assets acquired and the determination of the non-controlling interest. As a result, this is considered a key audit matter.	Our procedures included, but were not limited to: • Obtaining an understanding of the transaction, including an assessment of whether the transaction constituted an asset acquisition or business combination; • Reading the sale and purchase agreement to understand key terms and conditions including identifying of the acquirer; • Agreeing the consideration to supporting documentation; • Evaluating management's assessment of the fair value of the net assets acquired; • Reviewing the warrant documentation to ensure they had been appropriately accounted for; • Assessing the accuracy of the comparative information in the Financial Statement; and • Assessing the adequacy of the related disclosures in Note 4 and Note 23a to the Financial Report.

Other information

The Directors are responsible for the other information. The other information comprises the information in the Group's Annual Report for the year ended 31 December 2019, but does not include the Financial Report and the Auditor's Report thereon.

Our opinion on the Financial Report does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the Financial Report or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the Directors for the Financial Report

The Directors of the Company are responsible for the preparation of the Financial Report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the Directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the Directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the Financial Report

Our objectives are to obtain reasonable assurance about whether the Financial Report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

A further description of our responsibilities for the audit of the Financial Report is located at the Auditing and Assurance Standards Board website at: http://www.auasb.gov.au/auditors_responsibilities/ar1.pdf

This description forms part of our auditor's report.

Responsibilities

The Directors of the Company are responsible for the preparation and presentation of the Remuneration Report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the Remuneration Report, based on our audit conducted in accordance with Australian Auditing Standards.

Phillip Murdoch
Director

BDO Audit (WA) Pty Ltd
Perth, 6 May 2020

Unaudited additional shareholder information

In compliance with Oslo listing requirements and Section 3-3a of the Norwegian Accounting Act, the following information is provided in addition to the information set-out elsewhere in this Annual Report.

Reporting – payments to governments' statement

This country-by-country report has been developed to comply with the legal requirements in the Norwegian Security Trading Act ("Verdipapirhandelloven") § 5-5a, valid from 2014. The detailed regulation can be found in the regulation "Forskrift om land-for-land rapportering".

In 2019, the Company was engaged in extracting activities encompassed by the legislation above in the following countries: Republic of Congo, Nigeria, The Gambia, and Senegal. This report discloses relevant payments to governments for extractive activities in the countries above, in addition to some contextual information as required by the regulation in the "Forskrift om land-for-land rapportering".

Basis for preparation

The report includes direct payments to governments from subsidiaries, joint operations and joint ventures. In some cases, however, certain payments to governments may be made by an operator on behalf of a partnership. This is often the case for area fees. In such cases, the Company will report their paying interest share of the payment made by the operator.

Definitions

Government – In the context of this report, a government means any national, regional or local authority of a country. It includes a department, agency or undertaking controlled by that authority.

Project – For this reporting a project is defined as an investment in a concession agreement.

Licence fees – Typically levied on the right to use a geographical area for exploration, development and production and include rental fees, area fees, entry fees, severance tax and concession fees and other considerations for licences and/or concessions. Administrative government fees that are not specifically related to the extractive sector, or to access extractive resources, are excluded.

Materiality – As per the "Forskrift om land-for-land rapportering" payments made as a single payment, or as a series of connected payments that equal or exceed Norwegian Kroner (NOK) 800.000 during the year are disclosed.

Reporting currency – Payments to governments are converted from the functional currency of each legal entity into the presentation currency, United States Dollars (USD). The payments for entities whose functional currencies are other than USD are converted into USD at the foreign exchange rate at the average annual rate.

Payments to governments and contextual information

The consolidated overview below discloses the sum of the Company's payments to governments in each individual country where extractive activities are performed, per country/project.

Payments per project

Project	Royalties / USD' 000	Oil tax / USD' 000	Other amounts / USD'000	Total / USD'000
PNGF Sud	15,387	29,894	2,174	47,455
Total Republic of Congo	**15,387**	**29,894**	**2,174**	**47,455**
Aje	Nil	Nil	Nil	Nil
Total Nigeria	**Nil**	**Nil**	**Nil**	**Nil**
A1	Nil	Nil	Nil	Nil
A4	Nil	Nil	Nil	Nil
Total The Gambia	**Nil**	**Nil**	**Nil**	**Nil**
ROP	Nil	Nil	Nil	Nil
SOSP	Nil	Nil	Nil	Nil
Total Senegal	**Nil**	**Nil**	**Nil**	**Nil**

Other amounts includes payroll and other local taxes

Legal entities by country

as per the "Forskrift om land-for-land rapportering" it is required that the Company report on certain contextual information at corporate level. This includes information on localisation of subsidiary, employees per subsidiary and interests paid or payable to other legal entities within the Group.

Legal corporate structure of the Group during 2019 is set out below:

Name	Country of incorporation	Main country of operations	Employees[1]	Interest paid or payable to a group entity /USD
PetroNor E&P Ltd	Australia	United Kingdom	–	–
PetroNor E&P Ltd	Cyprus	Cyprus	1	387,025
PetroNor E&P AS	Norway	Norway	3	–
PetroNor E&P Services Ltd	United Kingdom	United Kingdom	2	–
PetroNor E&P Nigeria Ltd	Nigeria	Nigeria	2	–
Hemla African Holding AS	Norway	Norway	–	–
Hemla E&P Congo SA	Republic of Congo	Republic of Congo	5	–
African Petroleum Corporation Ltd	United Kingdom	United Kingdom	–	–
African Petroleum Corporation Ltd	Cayman Islands	United Kingdom	–	–
African Petroleum Gambia Ltd	Cayman Islands	The Gambia	1	–
African Petroleum Senegal Ltd	Cayman Islands	Senegal	–	–
African Petroleum Senegal SAU	Senegal	Senegal	1	–
African Petroleum Sierra Leone Ltd	Cayman Islands	Sierra Leone	–	–
African Petroleum (SL) Ltd	Sierra Leone	Sierra Leone	–	–
APCL Gambia B.V.	Netherlands	The Gambia	–	–
European Hydrocarbons Ltd	Cayman Islands	United Kingdom	–	–

1. Employees' number is the average during the year

Glossary and definitions

Bbl	One barrel of oil, equal to 42 US gallons or 159 liters
Bcf	Billion cubic feet
bbl/d	Barrels of oil per day
CPP	Production sharing contract, “Contrat de Partage de Production” in French
CPR	Competent Person’s Report
Group or PetroNor Group	PetroNor E&P Ltd and its subsidiaries
IOR	Improved oil recovery
MMbbl	Million barrels of oil
MMBOE	Million barrels of oil equivalent
Mmscfd	Million standard cubic feet per day
PDP	Proven Developed Producing (reserves)
PSC	Production sharing contract
SNPC	Société National des Pétroles du Congo

Directors

Eyas Alhomouz, Chairman
Joseph Iskander
Alexander Neuling
Jens Pace
Knut Søvold, Chief Executive Officer
Roger Steinepreis

Company Secretary

Angeline Hicks

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