PETRONOR E&P

Robust performance. Positioned for growth.

Annual report for the year ended
31 December 2020

Contents

About us

PetroNor E&P, listed on the Oslo Euronext Expand (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.

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 Vision

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 MMbbl and production of 30,000 barrels of oil equivalent per day (boepd) over a three year period.

Our Work

We are an independent oil and gas exploration and production company with licences in countries in West Africa – Republic of Congo, Guinea-Bissau, 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 in the MSGBC basin.

Find out more online:
www.petronorep.com

2020 & Post period

Completed a capital raise of NOK 340 million in March 2021 to fund acquisition of additional interest in PNGF Sud and to fund share of costs for next drilling activity at the asset.

PetroNor has increased its indirect ownership in PNGF Sud up to 16.83% through increasing its shareholding in Hemla E&P Congo and Hemla Africa Holding. The latter transaction is awaiting approval by the EGM 4 May 2021.

PNGF Sud production had a 4% growth in the oil production compared to 2019 with a gross field average production of 22,713 bopd in 2020.

PetroNor has further enhanced a highly attractive exploration portfolio in the West African margin through the entry in the Esperança and Sinapa licenses in Guinea-Bissau at highly attractive terms following the acquisition of SPE Guinea Bissau AB from Svenska Petroleum Exploration AB.

Extension of the long stop date for the Aje transaction from 31 December 2020 to 30 June 2021, allowing extra time for completion of the regulatory approval process in Nigeria which has been delayed by the COVID-19 pandemic.

EBITDA (USD)
33.97m
2019: 49.00m

EBIT (USD)
29.33m
2019: 45.77m

Net profit/(loss) (USD)
11.15m
2019: (5.76)m

2P Reserves (MMbbl)
20.23*
2019: 10.76

2C Contingent Resources (MMbbl)
14.11*
2019: 7.31

* Assuming the increase PNGF Sud in ownership had taken place as of 31 December 2020

Assets

Republic of Congo (Brazzaville)

10.5% indirect participation interest in the license group of PNGF Sud (Tchibouela II, Tchendo II and Tchibeli-Litanzi II) through Hemla E&P Congo S.A.

On 25 January 2021, the indirect participation interest increased to 11.9% after 9,900 shares in Hemla E&P Congo awarded by the court in Congo were registered for the benefit of the Company.

On 12 March 2021 a transaction to increase the indirect participation interest to 16.83% by acquisition of the non-controlling interest shares in Hemla Africa Holding AS, the transaction is subject to approval by the Extraordinary General Meeting which will be held 4 May 2021.

The Group holds a right to negotiate, in good faith, along with the contractor group of PNGF Sud, the terms of the adjacent license of PNGF Bis and a 14.7% indirect participation.

Nigeria

In 2019 acquired 13.1% economic interest in Aje Field through two transactions with Panoro Energy ASA and Yinka Folawiyo Petroleum. Started engaging with partners to streamline operations and made positive progress towards the Department of Petroleum Resources approval for both transactions. PetroNor will be the technical assistant to the Operator.

The MSGBC Basin

Further enhanced a highly attractive exploration portfolio across the MSGBC basin.

In April 2021, the approval for acquiring the 78.57% interest in the Sinapa and Esperança from Svenska Petroleum Exploration was received from the Government of Guinea-Bissau.

In September 2020, a new A4 license was awarded in The Gambia providing a 90% interest and operatorship to the Group.

In Senegal, the Rufisque Offshore Profond and Senegal Offshore Sud Profond license areas held by the Group are subject to arbitration with the Government of Senegal.

Eyas Alhomouz
Chairman

Transformational business

Last year presented numerous operational and corporate challenges as PetroNor, like all companies in the sector, was impacted by commodity price volatility and the broader issues created by the pandemic. Fortunately, the Company was able to ride out the turbulence and emerge healthy as a result of a robust cornerstone asset and a firm commitment to cost discipline.

The impact of the pandemic was severe on the oil and gas sector as demand came to a hard stop as global lockdowns came into force. Our activities were relatively unaffected as the operator did a good job of maintaining production at our asset in Congo, however the general backdrop created a lot of logistical challenges in communication and forward planning, resulting in delays to the completion of various corporate initiatives. The global rollout of vaccines has led to a good recovery in the sector and the global economic outlook, and we remain cautiously optimistic that the worst is behind us and that the Company is well placed to benefit from the macro tailwinds.

PetroNor's resilience through this turbulence reflects our diversified business model and commitment to cost control. The Company is continuously seeking to reduce its cost base and has made good headway in this regard, even prior to the pandemic. The diversification of the portfolio will continue to be a focus as we seek to achieve our stated ambition of becoming an established, full-cycle, Pan-African operator with the appropriate blend of production, development and exploration upside.

The sector turmoil in the last year, exacerbated by an accelerating Energy Transition, is creating a compelling market dynamic for PetroNor's inorganic growth

"PetroNor's resilience through this turbulence reflects our diversified business model and commitment to cost control."

strategy. The Company continues to actively screen and review opportunities consistent with our strategy, namely assets that provide immediate or near-term cash flow. We are witnessing a growing pipeline of opportunities of all sizes driven by the structural changes taking place in the industry. The industry ecosystem is changing and credible operators with a firm commitment to environmental and socioeconomic responsibilities will be required to enable the various stakeholders within the ecosystem to achieve their respective objectives. PetroNor is firmly positioned to be a partner of choice and we look forward to demonstrating these capabilities.

Our existing portfolio continues to evolve in line with our stated strategy. The pandemic has caused delays to completion of the Nigeria and Guinea-Bissau transactions however we are pleased that the Guinea-Bissau transaction received the required in-county regulatory approvals in late April 2021. The team has already put in a lot of technical work into the Aje re-development and our plans to reduce the flaring from that project will demonstrate our commitment to the reduction of the carbon footprint of our activities and overall approach to ESG. The settlement with The Gambia and reinstatement of the A4 licence vindicated our efforts to resolve that dispute and we look forward to working alongside the government in exploring that licence. We also hope to reach a solution with regards to Senegal and remain open to negotiation.

Our purpose is to ensure a positive impact with all that we do, and we are wholly focused on being a good citizen in the countries in which we work. We have active programmes in the Republic of Congo for education and continue to support the government in its fight against COVID-19. The Board seeks to continuously enhance its Governance and has made good progress in this regard with a stronger focus on Independence and Diversity in the boardroom. We will also continue to enhance our ESG agenda, recognising that this is a critical aspect of how we run our business.

The fundraise completed post-period, that enabled the transformative acquisition of an additional interest in PNGF Sud and funding for the infill drilling programme at the asset later this year, demonstrated the continued support the Company has from its shareholder base. These events will provide more scale and stability to the business, and leave us well placed to achieve our longer term growth objectives.

On behalf of the Board, I would like to thank all of our shareholders for their support and patience in these turbulent times. The Board and Management are wholly aligned with the wider shareholder base in terms of wishing to see PetroNor generate long-term sustainable value and believe that we have put in place the building blocks to enable that goal. I would also like to thank our management team for their commitment and believe that our team's experience and expertise are very much central to our investment proposition.

In summary, our Company has successfully navigated through the choppy waters of last year and is now well positioned to continue its growth journey with a positive wind in its sails. This year has the potential to be truly transformational for PetroNor and we look forward to communicating our progress as various operational and corporate initiatives come to fruition.

Sincerely,
Eyas Alhomouz
Chairman

"Our purpose is to ensure a positive impact with all that we do, and we are wholly focused on being a good citizen in the countries in which we work."

Our portfolio

Focusing on production, development and high-impact exploration of oil and gas opportunities across Africa

Production

Congo Brazzaville

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

Our asset, PNGF Sud is operated by Perenco – a world leading company specialised in low-cost tail production assets like PNGF Sud.

The reserves have increased year-on-year and the production has continued to grow and the operating cost has been significantly reduced, all achieved through work-over and maintenance work.

The license partnership has now embarked on a growth plan to drill more than 10 new wells with a three-year investment program of USD 250 million.

Production (net) (bopd)
3,850

2C Resources (net) (MMbbl)
8.81

2P Reserves (net) (MMbbl)
20.2

Development

Nigeria

Nigeria is a strategic target area for PetroNor due to the significant number of undeveloped assets in the country.

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 bopd 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.

2P Economic interest
13.1%

2C Economic Interest
17.4%

2P Reserves (net) (MMbbl)
0.2

2C Resources (net) (MMboe)
18.7

Nominal interest
6.5%

Production (net) (bopd)
260

Exploration

The MSGBC Basin

PetroNor has further enhanced a highly attractive exploration portfolio across the MSGBC (Mauritania-Senegal-Guinea-Bissau-Conakry) basins.

In late 2020, PetroNor entered into the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licenses offshore Guinea Bissau through the purchase of SPE Guinea Bissau AB from Svenska Petroleum Exploration.

Following completion in May 2021 PetroNor will assume Operatorship and an interest of 78.57% of the licenses. The offshore licenses, covering approximately 5,000 km², are located on a highly prospective trend in the MSGBC. The Atum and Anchova prospects are analogous to the world class Sangomar field in Senegal and are commercially attractive with net combined P50 recoverable prospective resources of 498 MMbbl (Svenska Petroleum Exploration estimate).

Net unrisked prospective resources (bbl)
4 Bn

Our portfolio

Production

Congo Brazzaville

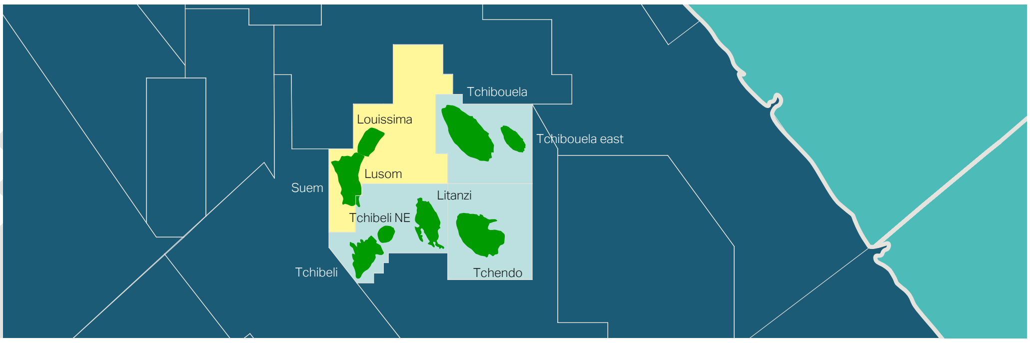
Production (net) (bopd)
3,850

2P Reserves (net) (MMbbl)
20.2

2C Resources (net) (MMbbl)
12.6

5 fields
16.83% Indirect Interest[1]

[1] The ownership in PNGF Sud is increased from 10.5 % to 16.83% during 2021 and will be completed when the EGM approved transaction is completed



The Republic of Congo (Congo-Brazzaville) is a leading producer of crude oil, representing around 90% of the exports of the country.

The majority of the production in Congo is located offshore, with approximately half in deep water.

PNGF Sud

Licence overview

In 2016 production rates were less than 15,000 bopd 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 year by year growth in both production and reserves.

Licence activity

Low cost production – lifting cost of 10.4 USD/bbl.

Gross production of 22,700 bopd (2020 average).

Very successful well workover programme to maintain a high number of active wells and effectively drain the significant in-place oil present where the recovery factor is only 23% to date.

New high-quality 3D reservoir models now being utilized for field management and planning of infill drilling activities starting late 2021 on several structures, of which 15 wells have been sanctioned only to date.

Continous de-bottlenecking of production system with particular emphasis on total fluid management.

Gross reserves and resources

	Volume (MMbbl)
2P	120.2
2C	43.4
STOIIP	2,029
Accumulated produced 01 January 2021	459

These reserves and resources are a result of a successful workover and infill drilling planning programme in all the PNGF fields. The remaining 2P reserves have more than doubled since 1 January 2017. Taking account of the 60% increase in PetroNor equity and production in the period, the reserves have increased by a factor of 3.6.

Net interest[2]

16.83%

Producing wells

65

[2] Figures assuming EGM approved transaction has been completed

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.

The three discovery wells tested from 1,150 to 4,700 bopd 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 tie-back to Tchibouela.

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

Net interest[2]

23.56%

Reserves growth through infill drilling 2021-23

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 recovery of 7.5 MMbbl.

Total estimated CAPEX of USD 105 million gross (14 USD/bbl) yielding attractive economics.

Economics attractive for reserve additions with between 8-13 USD/bbl of CAPEX.

Tchendo

Wellhead platform installed with available 14 slots for infill drilling of which seven have been sanctioned, following drilling of Litanzi in 2022.

Total cost USD 96 million including infrastructure and wells. The total cost for infrastructure and 14 wells is 9 USD/bbl.

Tchibeli

A four well infill program has been sanctioned and will follow the Tchendo drilling 2022. The total reserves is estimated to 7 MMbbl with a development CAPEX of 7.5 USD/bbl.

Tchibeli NE

A two well development programme is considered with ~12 MMbbl and development CAPEX of 7.5 USD/bbl with a 5 km tie-back to Tchibeli.

Our portfolio

Development

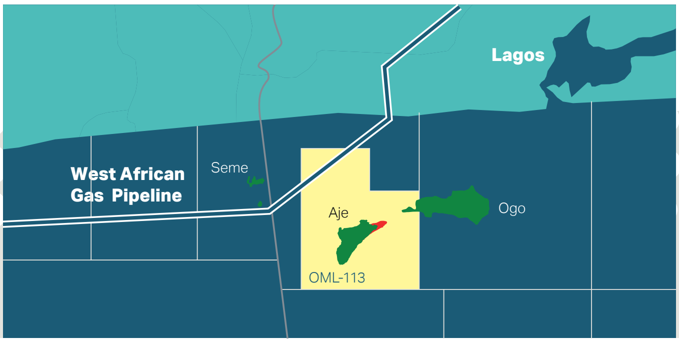
Nigeria

2C Resources (net) (MMbboe)
18.7

Production (bopd)
1,981
260 net

2P Reserves (net) (MMbbl)
0.2

Nominal interest
6.5%



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.

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 835 km² 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 Yinka Folawiyo Petroleum 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

Aje development plans are being finalised, and will be presented to the joint venture partners following the Nigerian government's approval of the transactions.

The development plans 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 Gas

Several scenarios are being considered and will be concluded prior to FID later in 2021. The Nigerian government encourages stop-flaring programs and the country is in dire need of electrical power.

Licence activity

Aje Field Development Plan ("FDP") is focused on producing and commercializing the gas. Condensate will be stripped from the gas produced offshore and "dry" gas will be reinjected until gas commercialization is available. The flared gas will be reinjected to stop the resource waste and allow for a gas recycling process.

Gas commercialization options include direct sales of rich gas through Gas Sales Agreements or through Swap agreement through GACN. The plan will include connecting to WAGP, which will be the main infrastructure for Gas delivery through sales or swap agreements. Further processing in a purpose- built gas plant is also considered to extract additional liquids (LPG and condensate) before the gas is sold to the local market.

The current FPSO is not suitable for the future FDP, and plans will include an FPSO suitable for FDP gas handing and processing.

2C Economic Interest

17.4%

2P Economic interest

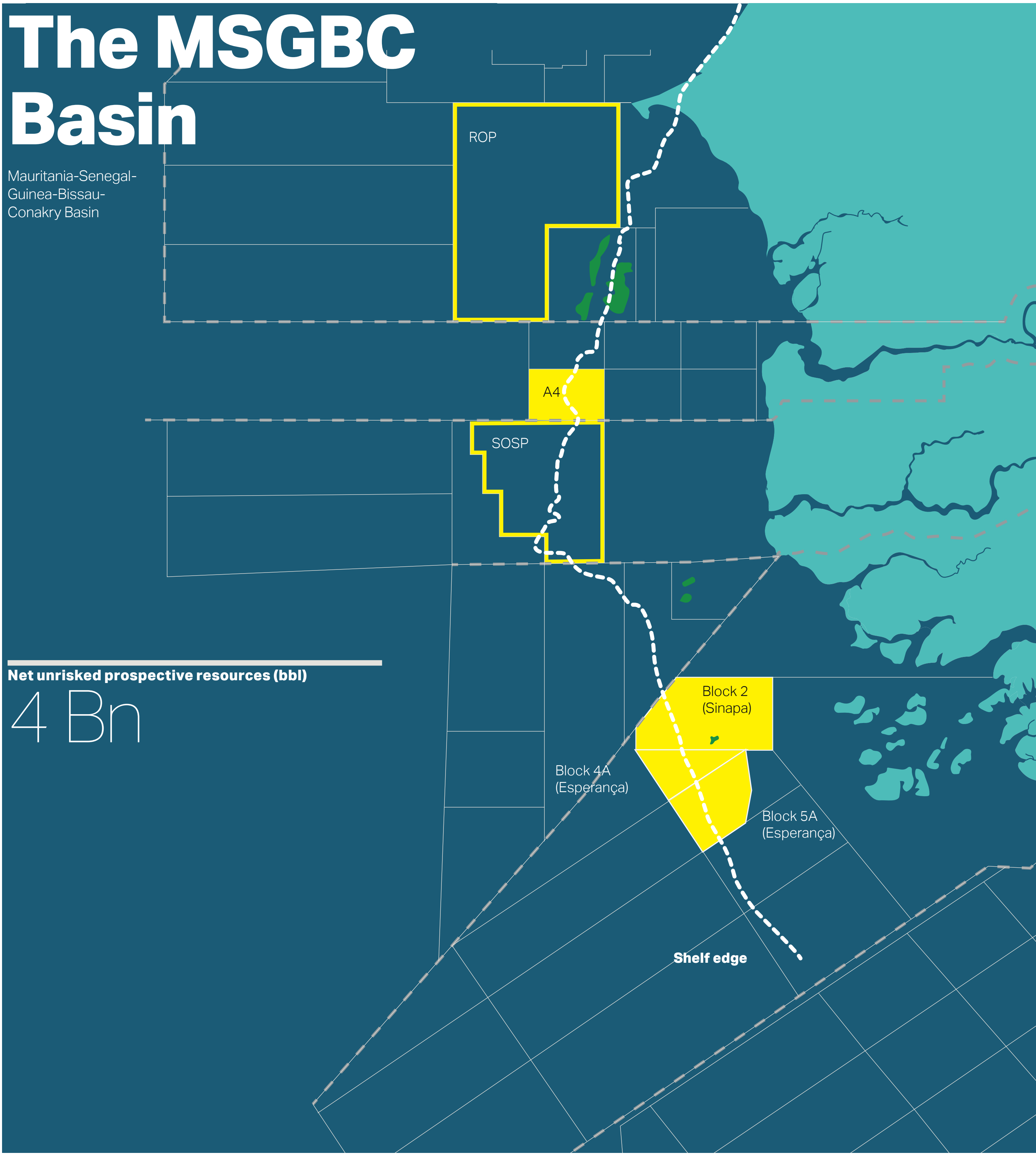
13.1%

Our portfolio

Exploration

The MSGBC Basin

Mauritania-Senegal-Guinea-Bissau-Conakry Basin



Net unrisked prospective resources (bbl)

4 Bn

Guinea-Bissau

Net working interest
78.57%

Area
4,963 km^2

Operator
PetroNor E&P AB

Net unrisked prospective resources (bbl)
>0.5 Bn

Licence overview
In October 2020, the current Exploration phases for the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences in Guinea-Bissau were extended for 3 years and are valid until October 2023.

The Company purchased SPE Guinea Bissau AB from Svenska Petroleum Exploration AB, and the transaction received formal in-country governmental approval in late April 2021. Subsequently, PetroNor has assumed operatorship of the licences through the renamed Svenska subsidiary acquired, PetroNor E&P AB.

During 2020, the operations on the licences were suspended due to COVID-19.

PetroNor intends to build on the work of the previous Operator, and re-initiate planning for drilling of the Atum-1X well, to test a highly attractive and material prospect on the Sinapa licence, analogous to the Sangomar field in Senegal. Recently reprocessed seismic data will be interpreted as part of the ongoing evaluation of both licences.

The Gambia

Net working interest
90%

Area
1,376 km^2

Operator
PetroNor E&P Gambia Ltd

Net unrisked prospective resources (bbl)
2.0 Bn

Licence overview
The Company was awarded a new 30-year lease for the A4 licence in September 2020. The award was part of a settlement agreement with the Government of The Gambia connected to the arbitration of the A1 and A4 licences previously issued in 2006.

The licence terms are based on the newly developed Petroleum, Exploration and Production Licence Agreement – PEPLA model. The Company will be able to carry the Prior Sunk cost associated with A4 into the new agreement for tax breaks and enhanced commercial model.

PetroNor will soon commence interpretation on reprocessed seismic data in support of seeking a partner to join the Company in drilling one exploration well in this highly attractive acreage that is on trend with the Sangomar field, 30 km to the North in Senegal. PetroNor aims to participate in any future well at an equity level of 30-50% and is seeking partners to help test the exciting portfolio of potential drilling opportunities.

Senegal

Net working interest
90%

Area
15,796 km^2

Operator
African Petroleum Senegal Ltd

Net unrisked prospective resources (bbl)
1.5 Bn

Licence overview
The Senegal Offshore Sud Profond and Rufisque Offshore Profond licences were awarded to the Company in 2011.

Arbitration proceedings with the International Centre for Settlement of Investment Disputes (ICSID) were registered in July 2018 (case ARB/18/24) to protect PetroNor's interests in the licences.

Between May 2020 and April 2021, the arbitration proceedings were halted to allow discussions between the parties to try and reach a mutually beneficial solution, disappointingly to no avail.

The Company remains confident in its legal position and will progress the arbitration proceedings to an independent judgement.

Knut Søvold
Chief Executive Officer

We delivered a number of transformative events that leave the Company exceptionally well placed to achieve its long-term objectives

We believe that it is a very opportunity rich market for a company like PetroNor, and we have every confidence that we can achieve scale through organic and inorganic means.

PetroNor delivered a resilient performance in what was an unprecedented period for the sector and the global economies as a result of the COVID-19 pandemic. The sudden impact of the pandemic on global demand, and therefore commodity pricing, was both rapid and severe. However, the Company took swift and appropriate action to control costs and has subsequently emerged in robust health. Pleasingly, the sector has rebounded quickly which has enhanced the economics of our production, and also improved the general industry and investor sentiment. In this context, post period, we delivered a number of transformative events, as set out below, that leave the Company exceptionally well placed to achieve its long-term objectives.

The Company moved quickly to capitalise on the improving backdrop, and in the recent months announced a series of transformative corporate events that saw us increase our interest in our cornerstone asset in Congo and strengthen the balance sheet. The acquisition of an additional interest in PNGF Sud is accretive on every metric, enhancing our production, cash flow and reserves.

The associated fundraise in Q1-2021 also ensures the Company is fully-funded for its share of the infill drilling programme in PNGF Sud that will take place in the next 12 months, the successful execution of which will materially enhance our production and cash flow further. The PNGF Sud asset has been the bedrock of our company, and will continue to be so for many years to come given the independently verified upside that remains in the field.

The CPR issued by AGR Petroleum Services in March 2021 demonstrated the continued strong performance of this high quality and economically robust asset, and emphasised the significant value yet to be realised, with PetroNor's net working interest 2P Reserves amounting to 20.23 MMbbl with 2C contingent resources of 7.3 MMbbl (position after aqusition of additional interest). The update represents an increase of approximately 28% and 49% for 2P and 2C respectively on a gross basis, and a 2P reserves replacement for 2020 of over 300%. The Operator Perenco has done an exceptional job of building out the production to bring new life to the asset, and we look forward to benefiting from the continued success of this asset with a more meaningful interest going forward.

In 2020 PetroNor made significant progress in a number of strategic areas as we sought to further diversify the portfolio in line with our strategic vision of establishing the Company as a leading, full-cycle, Pan-African Operator. The addition of high potential acreage in Guinea-Bissau will deliver more high impact assets to our portfolio when that transaction completes, and will enhance our ability to monetise our exploration assets in due course.

We were also pleased to reach a settlement with regards to our long-running arbitration with The Gambia which saw PetroNor regaining the A4 block; a highly prospective block in one of the most exciting hydrocarbon basins in the world. The terms of the new license are significantly more attractive and will enhance not only the value of the license but also its attractiveness to potential partners. This was a positive outcome for the Company and its shareholders, and justified the efforts of the Company to instigate arbitration and to pursue a settlement.

Throughout last year and Q1 of this year, the Company continued to engage with the Senegal authorities to establish a similarly positive outcome, and while progress was made in the year as both parties agreed to pause the arbitration proceedings with a view to seek an out of court settlement, no such agreement has been made and the process has recently returned to arbitration. The Company remains open to re-initiation of negotiations, however equally remains confident in its legal position and looks forward to seeing the case resolved through independent channels.

The strategy to establish a portfolio of exploration assets in West Africa with high working interests is designed to provide PetroNor with optionality to monetise its early mover advantage with regards to these high-impact assets. These assets are far from wildcat, but rather well progressed assets with numerous drill ready prospects and leads, in a region that continues to see strong industry interest.

Whilst the industry has undoubtedly changed as a result of the Energy Transition and certain majors are shifting focus away from exploration as a result of ESG pressures, we continue to see strong interest in high quality assets and feel confident that we can monetise these assets over time, whilst retaining exposure to exciting drill-bit led value catalysts.

While the Company continues to progress its monetisation strategy of its exploration portfolio, it will continue to explore other opportunities in line with its diversification strategy.

The previously announced transaction with Panoro to farm into the Aje development in Nigeria has been frustratingly delayed as a result of the pandemic, but we expect to see that complete this year, and much work has taken place to work up the re-development concept so that work can commence swiftly following final ratification of that transaction.

The theme of the Energy Transition has gained momentum through the last year, and this is a theme that the Board of PetroNor wholly embraces given the risks that climate change poses to all humanity. In Africa however, the Transition poses its very own immediate risk to the environmental and socioeconomic development of the countries, and people, that rely on the revenue from its discovered resources.

It is well known that many hundreds of millions of Africans do not have access to reliable electricity and the continent will not be transitioning to a greener economy at the same pace as more developed nations. As such, we believe that it is the moral obligation of credible operators such as PetroNor to play its role in enabling a smooth and steady transition that enables the continent to continue to benefit from its natural resources until a more viable and sustainable solution is ready.

The Transition presents PetroNor with a strong opportunity, as IOCs and Majors divest mid-to-later life assets in order to meet their carbon reduction targets. Given our strong network and growing reputation as a credible and responsible operator, we are positioning ourselves as a consolidator of choice, and will be engaging with Governments and IOCs to see how we can help them deliver their respective agendas. Through 2020 and this current year, our business development team has been screening opportunities of various sizes in line with our strategic intent, and hope to deliver more value accretive inorganic growth in the coming years, and achieve the scale that makes us more relevant and more capable of generating sustainable shareholder returns.

ESG is also a growing theme as investors rightly scrutinise companies in detail regarding the way in which they run their business and manage the impact of their activities and the risks that they pose. The Company has always operated with a mindset of sustainability and seeks to ensure positive socioeconomic impact from its activities.

The Company has also made significant efforts to enhance its Governance through the year, reconstituting the Board with a stronger focus on independence. In February of this year, we announced that my co-founder of the business, Mr. Gerhard Ludvigsen, was departing his role on the Board and Executive team, but will continue to provide support to the Company on an ongoing consultancy basis, with a particular emphasis on developing PetroNor's ESG agenda.

The appointment of Mrs. Gro Kielland, a highly credible industry figure, was a demonstration of our growing industry credibility and ambitious intent. In early 2020, we also announced the change of CEO, with Mr. Jens Pace moving to a Non-Executive role, and myself taking over. We believe that PetroNor has assembled a highly experienced, dynamic and ambitious team, with a diverse technical and commercial skillset, capable of delivering long-term value for our shareholders.

This year, we hope to build on the momentum we have already achieved, and deliver a number of material corporate and operational milestones. We believe that it is a very opportunity rich market for a company like PetroNor, and we have every confidence that we can achieve scale through organic and inorganic means. Specifically, we are happy to have concluded the Guinea-Bissau transaction and hope to conclude our previously announced transaction in Nigeria, and make positive headway in monetizing the exploration portfolio that we have assembled. We also look forward to the infill drilling programme on PNGF Sud, and the step-change in production and cash flow that will bring to the Company following completion of the recently announced transaction.

In summary, 2020 was a challenging yet strategically transformational year for PetroNor and the Company is well placed to benefit from an improving industry backdrop and a growing pipeline of compelling and strategically complementary opportunities presenting themselves as a result of the structural changes happening in the sector. The Company has established a diverse portfolio of assets delivering robust cash flow and extraordinary upside potential, and we remain focused on delivering sustainable shareholder value as we progress our strategic and operational initiatives through this year and beyond.

Sincerely,
Knut Søvold
Chief Executive Officer

Introduction

PetroNor's classification of reserves and resources complies with the guidelines established by the Oslo Stock Exchange and are 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 ("AGR") in March 2021 for PNGF Sud and PNGF Bis.

PetroNor assets portfolio

PetroNor's assets are located approximately 25 km off the coast of Pointe Noire in water depths of 80-100 metres. PetroNor, through Hemla E&P Congo S.A. (HEPCO), participated in the 2016 tender process with the Ministry of Petroleum of the Republic of Congo 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 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 ASA ("Panoro"). An agreement was also made between PetroNor and Yinka Folawiyo Petroleum ("YFP") to jointly further develop OML-113. These agreements are described in further detail in the Director's report. This transaction is not yet completed and is not part of this ASR statement.

The exploration assets in Guinea-Bissau, The Gambia and Senegal only constitute prospective resources, therefore are not considered part of this Annual Statement of Reserves ("ASR").

PNGF Sud

Offshore Congo Brazzaville, operator Perenco, PetroNor 10.5%.

PNGF Sud is a development and exploitation license covering an area containing several oil fields, Tchibouela, Tchibouela East, Tchendo, Tchibeli and Litanzi fields. The interest in PNGF Sud is held directly by HEPCO with a 20% share. Through PetroNor's ownership of 52.5% of HEPCO, this constitutes an indirect 10.5% share in the PNGF Sud licenses. The ownership of the licences has been effective since 1 January 2017 with an expiry date after 20 years plus a 5-year extension period. Since granting of the licenses, 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 March 2021 AGR performed a full Competent Persons 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 of 31 December 2020.

Gross production during 2020 was 8.31 MMbbls of oil and 1.0 Bcf of gas. This corresponds to average 22,713 bopd and 2.7 mmscfd.

As per the PRMS/SPE guidelines, only a portion of gas is contributing to power generation (on Tchibouela only) and 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 MMbbls do not include the oil equivalent gas but are included in the appendix reserves and resource tables.

This PetroNor ASR uses as the basis the Reserves and Resources from the March 2021 AGR CPR yielding Reserves and Resources as per 31 December 2020. 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 MMbbls.

As at 31 December 2020, AGR evaluated that gross 1P Proved Reserves yield 86.20 MMbbls in all of the PNGF Sud fields in the Cenomanian, Turonian, Senonian and Albian reservoirs. Gross 2P Proved plus Probable Reserves at PNGF Sud amounted to 120.2 MMbbls in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at PNGF Sud amounted to 152.4 MMbbls.

Gross 1C Resources yield 26.0 MMbbls in all of the PNGF Sud fields in the Cenomanian, Turonian, Senonian and Albian reservoirs. Gross 2C Resources at PNGF Sud amounted to 43.4 MMbbls in the same reservoirs. Gross 3C Resources at PNGF Sud amounted to 74.6 MMbbls.

These evaluations yield 1P Proved Reserves net to PetroNor of 9.05 MMbbls, 2P Proved plus Probable Reserves net to PetroNor of 12.62 MMbbls and 3P Proved plus Probable plus Possible Reserves net to PetroNor of 16.00 MMbbls.

Additional potentially recoverable resources net to PetroNor are approximately 2.7 MMbbls 1C, 4.6 MMbbls 2C and 7.8 MMbbls 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 license neighbours the PNGF Sud licences and contains two discoveries, Louissima and Loussima SW. The two discoveries are proven by three wells including DST's drilled from 1985-1991. 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 the production levels with additional producers as resources are matured to reserves.

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

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 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 2020 ASR.

PNGF Sud

During all the years from 2017 to 2020, production levels have grown from the initial c. 15,000 bopd when Perenco and partners took over. This has materialized through revitalizing existing producers via replacements or upsizing of Electrical Submersible Pumps ("ESPs"), acidizing, clean up or reperforating wells or converting wells from the Cenomanian to the Turonian (less depleted) formations. Significant surface debottlenecking is also taking place, 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 2020 of 22,713 bopd. The production improvements alone have yielded more than a 100% reserves replacement each year at a cost of less than 1 USD/bbl. In addition to this, significant infill drilling potential has been identified in all fields and justified for investment, so far in three of these, the Litanzi, Tchendo and Tchibeli.

The start of infill drilling has in 2020-2021 been delayed by COVID-19, however, significant investments have already been made in infill drilling infrastructure to accommodate offtake, process and well slots. An infill drilling program was decided for the Litanzi field in 2019 and in 2020 for Tchendo and Tchibeli. Consequently the 2C resources in these fields have been converted to 2P reserves. Development of 3D static and dynamic models has been and will continue to form the basis of further infill drilling programmes on PNGF Sud. In recognition of the infill potential existing on Tchibouela there has been an increase also in the 2C resources in this field.

In summary for all fields, the conversion of 2C to 2P and the increase in 2P reserves between 2019 and 2020 constitutes 26.0 MMbbls. This corresponds to a 2P increase of 28%. With gross produced volumes during 2020 of 8.3 MMbbls, this represents a reserve replacement ratio of 313%. Additionally, the increase in 2C resources is 14.2 MMbbls, primarily reflecting the further infill potential in Tchibouela.

PNGF Bis

Once investment decisions are made on the Loussima SW project these reserves may become reserves approved for development. The 2C resources in PNGF Bis have been reaffirmed by AGR as part of this years' reserves and resource audit without change to the numbers. It is expected that these discoveries will have priority following the infill drilling programmes in PNGF Sud. Given a successful Loussima SW, a similar development potential is also 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 in 2020 were at 10.4 USD/bbl.

2020 – 2P Reserves	(MMbbls)
Balance (gross AGR, PNGF Sud – 31.12.2020)	120.2
Balance 31.12.2020 – 2P net, PNGF Sud	12.6

2P and 2C Reserves and Resources Status	(MMbbls)
Balance 31.12.2020 – 2P/2C gross, PNGF Sud	163.6
Balance 31.12.2020 – 2P/2C net, PNGF Sud	17.2
Balance 31.12.2020 – 2P/2C gross, Sud+Bis	192.5
Balance 31.12.2020 – 2P/2C net, Sud+Bis	21.4

PetroNor's total 1P Reserves at end of 2020 amounted to 9.05 MMbbls. PetroNor's 2P Reserves amount to 12.62 MMbbls and PetroNor's 3P Reserves amount to 16.00 MMbbls. This reflects the March 2021 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 end of 2020, PetroNor's assets contain a total 2C volume of approximately 8.8 MMbbls.

29 April 2021
Knut Søvold
Chief Executive Officer

Reserves and resources as per 31 December 2020 (AGR CPR dated 10 March 2021)

Gross Reserves (developed or under development)

	1P			2P			3P		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
100% PNGF Sud									
Tchibouela	50.80	11.90	52.90	62.80	16.90	65.80	76.40	25.40	80.90
Tchendo	21.10	–	21.10	28.90	–	28.90	36.00	–	36.00
Tchibeli	7.40	–	7.40	17.70	–	17.70	26.50	–	26.50
Litanzi	6.90	–	6.90	10.80	–	10.80	13.50	–	13.50
Subtotal	**86.20**	**11.90**	**88.30**	**120.20**	**16.90**	**123.20**	**152.40**	**25.40**	**156.90**
100% PNGF Bis									
Loussima (Bis)	–	–	–	–	–	–	–	–	–
Total	86.20	11.90	88.30	120.20	16.90	123.20	152.40	25.40	156.90

Gross Contingent Resources (undeveloped)

	1C			2C			3C		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
100% PNGF Sud									
Tchibouela	14.70	8.90	16.30	23.10	13.80	25.50	37.40	22.30	41.30
Tchendo	5.40	–	5.40	9.10	–	9.10	19.20	–	19.20
Tchibeli	5.90	–	5.90	11.20	–	11.20	18.00	–	18.00
Litanzi	–	–	–	–	–	–	–	–	–
Subtotal	**26.00**	**8.90**	**27.60**	**43.40**	**13.80**	**45.80**	**74.60**	**22.30**	**78.50**
100% PNGF Bis									
Loussima (Bis)	22.40	–	22.40	28.90	–	28.90	35.80	–	35.80
Total	**48.40**	**8.90**	**50.00**	**72.30**	**13.80**	**74.70**	**110.40**	**22.30**	**114.30**

Net to PetroNor - Reserves and resources as per 31 December 2020 (AGR CPR dated 10 March 2021)
Reserves are shown according to the ownership in PNGF Sud as of 31 December 2020, the subsequent change in owernship in PNGF Sud from 10.5% to 16.83% is not reflected in the tables below.

Net PetroNor Reserves (developed or under development)

	1P			2P			3P		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
10.50% PNGF Sud									
Tchibouela	5.33	1.25	5.55	6.59	1.77	6.91	8.02	2.67	8.49
Tchendo	2.22	–	2.22	3.03	–	3.03	3.78	–	3.78
Tchibeli	0.78	–	0.78	1.86	–	1.86	2.78	–	2.78
Litanzi	0.72	–	0.72	1.13	–	1.13	1.42	–	1.42
Subtotal	**9.05**	**1.25**	**9.27**	**12.62**	**1.77**	**12.94**	**16.00**	**2.67**	**16.47**
14.70% PNGF Bis									
Loussima (Bis)	–	–	–	–	–	–	–	–	–
Total	**9.05**	**1.25**	**9.27**	**12.62**	**1.77**	**12.94**	**16.00**	**2.67**	**16.47**

Net PetroNor Contingent Resources (undeveloped)

	1C			2C			3C		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
10.50% PNGF Sud									
Tchibouela	1.54	0.93	1.71	2.43	1.45	2.68	3.93	2.34	4.34
Tchendo	0.57	–	0.57	0.96	–	0.96	2.02	–	2.02
Tchibeli	0.62	–	0.62	1.18	–	1.18	1.89	–	1.89
Litanzi	–	–	–	–	–	–	–	–	–
Subtotal	**2.73**	**0.93**	**2.90**	**4.56**	**1.45**	**4.81**	**7.83**	**2.34**	**8.24**
14.70% PNGF Bis									
Loussima (Bis)	3.29	–	3.29	4.25	–	4.25	5.26	–	5.26
Total	**6.02**	**0.93**	**6.19**	**8.81**	**1.45**	**9.06**	**13.10**	**2.34**	**13.51**

Pro forma net to PetroNor - Reserves and resources as per 31 December 2020
Reserves are shown according to the ownership in PNGF Sud on a pro forma basis assuming the increase in ownership has taken place as of 31 December 2020

Net PetroNor Reserves (developed or under development)

	1P			2P			3P		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
16.83% PNGF Sud									
Tchibouela	8.55	2.00	8.90	10.57	2.84	11.07	12.86	4.27	13.62
Tchendo	3.55	–	3.55	4.86	–	4.86	6.06	–	6.06
Tchibeli	1.25	–	1.25	2.98	–	2.98	4.46	–	4.46
Litanzi	1.16	–	1.16	1.82	–	1.82	2.27	–	2.27
Subtotal	**14.51**	**2.00**	**14.86**	**20.23**	**2.84**	**20.73**	**25.65**	**4.27**	**26.41**
23.6% PNGF Bis									
Loussima (Bis)	–	–	–	–	–	–	–	–	–
Total	**14.51**	**2.00**	**14.86**	**20.23**	**2.84**	**20.73**	**25.65**	**4.27**	**26.41**

Net PetroNor Contingent Resources (undeveloped)

	1C			2C			3C		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
16.83% PNGF Sud									
Tchibouela	2.47	1.50	2.74	3.89	2.32	4.29	6.29	3.75	6.95
Tchendo	0.91	–	0.91	1.53	–	1.53	3.23	–	3.23
Tchibeli	0.99	–	0.99	1.88	–	1.88	3.03	–	3.03
Litanzi	–	–	–	–	–	–	–	–	–
Subtotal	**4.38**	**1.50**	**4.65**	**7.30**	**2.32**	**7.71**	**12.56**	**3.75**	**13.21**
23.6% PNGF Bis									
Loussima (Bis)	5.29	–	5.29	6.82	–	6.82	8.45	–	8.45
Total	**9.66**	**1.50**	**9.93**	**14.12**	**2.32**	**14.53**	**21.00**	**3.75**	**21.66**

Responsible business

By embracing the growing awareness of ESG, PetroNor E&P is committing to operating responsibly. Having local management on the ground in our countries of operation is an important part of anchoring our activities to the local society and that the company is well suited to support local growth with our projects.

Environmental

PetroNor strives that our operations minimise any adverse impact on the environment and is fully committed to environmental stewardship.

As an integral part of any development, we always undertake Environmental Impact Assessments ("EIA") prior to all major activities & communicate results to stakeholders.

The Aje project in Nigeria will provide cleaner fuel to a region which is hungering for energy. Our plans for the Aje redevelopment will provide low emission energy corresponding to 5% of the total power production of Nigeria.

The Aje gas development will lead to displacement of gasoline used for power generation in Lagos.

Social

During the last few years, we have set aside 5% of our net profits in Congo Brazzaville towards social programs.

A key focus has been on education, as shown in our case example: 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.

Governance

In 2020 PetroNor joined the Extractive Industries Transparency Initiative.

With an open business model, PetroNor aims to increase access to opportunities for local growth through the formation of subsidiary companies with indigenous partners.

Our company is continuously working towards diversification both at board level and in the organisation.

According to United Nations, of all regions in the world, sub-Saharan Africa has the highest rates of education exclusion. Over one-fifth of children between the ages of about 6 and 11 are out of school, followed by one-third of youth between the ages of about 12 and 14. According to UIS data, almost 60% of youth between the ages of about 15 and 17 are not in school.

Locations of our six supported elemenary schools

Elementary schools in Congo Brazzaville

Our company is engaged in a number of developing countries in Africa. We see education as a strong driver for development across the continent where continued support and strengthening of elementary education is still in need. Our group has supported construction of six elementary schools in the Republic of Congo in 2019 and 2020. The school buildings are equipped with electrical light and clean water. Our hope is that our contribution can be one of many.

As a company we appreciate that education is an important factor for growth in any society.

The Board

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 a 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.

CEO of Petromal LLC a subsidiary of National Holding in Abu Dhabi.

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.

EIIC is a subsidiary of National Holding in Abu Dhabi.

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, UK.

Experience
Mr. Pace is a highly regarded geoscientist, who has had a successful career 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, and has managed a very large and active exploration portfolio for BP in Africa. Additionally, Mr. Pace has gained highly sought-after experience in the areas of field development and as a commercial manager, dealing with national oil companies and African governments.

Following the merger with PetroNor E&P Ltd on 30 August 2019, Mr. Pace resigned as Chief Executive Office on 29 February 2020, but remains on the Board as a Non-Executive Director.

A diverse and experienced team

Ingvil Smines Tybring-Gjedde
Non-Executive Director

Qualifications
Mrs. Smines Tybring-Gjedde graduated from BI Norwegian Business School with a Masters degree in Management Programs, with strong focus on Interaction and Leadership and Strategy.

Experience
Experienced former Norwegian Minister of National Public Security with overall responsibility of public safety, emergency planning, and cybersecurity. Mrs. Tybring-Gjedde was also Minister of Svalbard and the Norwegian polar regions. Before her position as Minister, she served as Deputy Minister in the Ministry of Petroleum and Energy for 4 years, with a portfolio of exploration policy, development, and operations, exploration activity as well as following the Ministry's contact with other petroleum-producing countries and international forums in addition to the government's national climate policy, global environmental issues and the government's CCs full-scale project. Mrs. Tybring-Gjedde has a demonstrated history of working in the O&G, energy, and renewable industry in private and state-owned companies in various leading positions for more than 20 years.

Gro Kielland
Non-Executive Director

Qualifications
Mrs. Kielland holds an MSc in Mechanical Engineering from the Norwegian University of Science and Technology (NTNU).

Experience
Mrs. Kielland has over 30 years of experience having held a number of leading positions in the oil and gas industry both in Norway and abroad, among others as CEO of BP Norway. Her professional experience includes work related to both operations and field development, as well as HSE.

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.

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.

Senior Management

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, from 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, UK, 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 bopd. 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.

Mr. Søvold is a founding member of PetroNor.

Claus Frimann-Dahl
Chief Technical Officer

Qualifications
Mr. Frimann-Dahl holds a BSc in Petroleum Engineering from Texas A&M University and an MSc from the University of Trondheim (NTH).

Experience
Mr. Frimann-Dahl has 30 years' experience from the oil and gas industry, with managerial and technical roles. His experience covers operational roles with Phillips Petroleum, Norsk Hydro and Hess in the North Sea Norway and Denmark, Russia, Egypt and the US. He was the co-founder of Ener Petroleum which was later acquired by Dana Petroleum and KNOC.

Michael Barrett
Exploration Manager

Qualifications
Mr. Barrett holds a BSc in Geology & Geophysics from Durham University and a MSc in Petroleum Geology & Geophysics from Imperial College, Royal School of Mines.

Experience
Mr. Barrett has 30 years of global exploration experience from his career at Chevron Corporation, and more recently with an Africa specific focus at Addax/Sinopec International and African Petroleum. Mr. Barrett has held a variety of senior technical roles covering exploration and new ventures, and was part of Chevron's global Exploration Review Team, specialising in Play and Prospect risk and volumetric assessment. He has extensive experience in portfolio management and commercial evaluation of oil and gas opportunities.

Emad Sultan
Strategy and Contracts Manager

Qualifications
Mr. Sultan holds a BSc in Mechanical Engineering from the University of Washington.

Experience
Mr. Sultan has 20 years of international Exploration & Production experience. He has held multiple operation and marketing management positions with international oil field services companies. He has also worked in a number of technical, contracting and strategy management roles with major oil and gas operators.

Chris Butler
Group Financial Controller

Qualifications
Mr. Butler is a Fellow of the Institute of Chartered Accountants in England and Wales and holds a BSc in Physics from Warwick University, UK.

Experience
Mr. Butler has 16 years of financial and corporate experience from positions in public practice, oil & gas and mining spread over Africa, Asia and Europe, with roles that included financial reporting, contract negotiations, M&A, due diligence, treasury and several system implementations.

Angeline Hicks
Company Secretary

Qualifications
Chartered Accountant

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.

The Directors present their report on PetroNor E&P Limited ("PetroNor" or the "Company") for the year ended 31 December 2020.

Directors & Company Secretary

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.

	Role	Appointed	Resigned
Current members:			
E Alhomouz	Non-Executive Chairman	-	-
J Iskander	Non-Executive Director	-	-
J Pace	Executive Director Chief Executive Officer	-	29 Feb 2020
	Non-Executive Director	01 Mar 2020	-
A Neuling	Non-Executive Director	06 Apr 2020	-
R Steinepreis	Non-Executive Director	06 Apr 2020	-
I Tybring-Gjedde	Non-Executive Director	29 May 2020	-
G Kielland	Non-Executive Director	01 Feb 2021	-
A Hicks	Company Secretary	-	-
Former members:			
K Søvold	Executive Director	-	29 May 2020
	Chief Executive Officer	29 Feb 2020	-
G Ludvigsen	Executive Director	29 May 2020	31 Jan 2021
S West	Executive Director	-	29 Feb 2020
T Turner	Non-Executive Director	-	08 Feb 2020
D King	Non-Executive Director	-	01 Feb 2020

Principal Activity

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

Review of Operations
Corporate

Board Appointments & Resignations

After the successful integration of the Company and African Petroleum Corporation Ltd in 2019, three of the former Directors from African Petroleum resigned during February 2020 to streamline the Board and management structure. At the same time, Knut Søvold was promoted internally to the position of Chief Executive Officer, having been a founding member of PetroNor, whereas former African Petroleum CEO, Jens Pace, stepped down from the role but continues to serve the Company as a Non-Executive Director.

After the AGM on 29 May 2020, Gerhard Ludvigsen and Ingvil Smines Tybring-Gjedde were formally appointed to the Board of Directors. However, with the stated aims to adopt more standard Norwegian governance procedures, Knut Søvold relinquished his position on the Board of Directors and continues to serve as CEO of the Company.

On 1 February 2021, Gro Kielland was appointed as an Independent Director to replace Executive Director Gerhard Ludvigsen, to further strengthen the governance procedures.

Gro Kielland is a highly experienced and credible industry figure, having previously been the former CEO of BP Norway, and currently holding a number of non-executive roles, including a role on the Board of AkerBP, a company with a market cap of NOK 85 billion and a production of around 200,000 bopd.

Mr. Ludvigsen relinquished his position on the executive team, however, he remains with the Company in an advisory role with specific focus on the Company's effective ESG strategy.

Following these changes, the Board consists of seven Directors, of which five are considered to be independent.

Free Float & Market Making

Post period, the free float of the Company exceeded 25%, for the first time since the merger with African Petroleum in 2019. The Directors hope to further broaden and diversify its shareholder base with the announced contemplated equity financing event.

In keeping with similar sized companies, the Company commenced a market making agreement with SpareBank 1 Markets AS on 3 November 2020, with the primary purpose of enhancing the liquidity in the trading of the Company's shares listed on Euronext Expand. The agreement was for a 6-month period, and the performance will be evaluated before the Company commits to renewing the agreement.

Corporate Restructuring

The plans previously announced in February 2020, to redomicile the Company to Europe during H2-2020 in order to streamline the corporate structure and reduce corporate overheads have not yet been executed. The entire process is estimated to take 3 months, but this project has been delayed due to COVID-19 and is now expected to take place in Q2-2021.

EITI - Supporting Company

During 2020, the Company became a supporter of the Extractive Industries Transparency Initiative ("EITI"), and thereby wish to promote transparency throughout the extractive industries, help public debate and provide opportunities for sustainable development.

COVID-19

The Company adapted quickly to the limitations on travel due to restrictions on social mobilty imposed by Governments around the world. Plus with additional cost control measures put in place at the outset of the pandemic, the Company managed to continue trading throughout. The overall impact of COVID-19 on the Company is hard to assess, however it has delayed the plans by the Directors to grow the Company since the reverse takeover in 2019 by approximately one year.

Review of Operations
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 80-100 metres. PNGF Sud comprises 3 operating licenses, Tchibouela II, Tchendo II and Tcibeli-Litanzi II, covering five oil fields: Tchibouela Main, Tchibouela East, Tchendo, Tchibeli and Litanzi. PetroNor, through Hemla E&P Congo S.A., participated in the 2016 tender process with the Congo Ministry of Hydrocarbon for participation in the PNGF Sud licenses. As of 1 of January 2017, Hemla E&P Congo S.A. 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 65 wells from its five oil fields.

Following the entry of the new license group in 2017, significant operational improvements have been made, increasing gross production from c. 15,000 bopd in January 2017 to an average production in 2020 of 22,713 bopd. 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 65 active production wells, with oil exported via the onshore Djeno terminal. 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 cost.

In March 2021, AGR Petroleum prepared a Competent Person's Report whereby the reserves below are calculated to 31 December 2020.

PetroNor's Reserves as at 31 December 2020 were:
- 1P reserves of 9.05 MMbbls.
- 2P reserves of 12.62 MMbbls
- 3P reserves of 16.00 MMbbls.

PetroNor's Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By end of 2020, PetroNor's assets contain a total 2C volume of approximately 8.81 MMbbls.

During 2020, the gross production was 8.31 MMbbls of oil and 1.00 Bcf of gas, resulting in a net to PetroNor production of 2,385 bopd.

On 27 October 2020, in relation to a dispute concerning PNGF Sud, the Court of Appeal rejected an appeal against certain shareholders in PetroNor and the subsidiary Hemla Africa Holding AS ("HAH") and the appellant was ordered to cover the costs in connection with the appeal.

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 license partners of PNGF Sud have the right to negotiate, in good faith, the license terms to enter into a PSC for PNGF Bis.

Three exploration wells have been drilled on this license 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 bopd and the SUEM-2 well yielded 1,150 bopd.

The CPR report prepared by AGR estimates that PNGF Bis holds gross 2C resources of 28.90 MMbbl.

The Gambia
A4
During September 2020, the Company reached a mutual agreement with the Government of The Gambia to settle its arbitration related to the A1 and A4 licences. PetroNor relinquished any claims related to the A1 licence and regained the A4 licence with a new 30-year lease under new terms.

The terms of the new licence are based on the newly developed Petroleum, Exploration and Production Licence Agreement - PEPLA model. The Company will be able to carry the Prior Sunk cost associated with A4 into the new agreement for tax breaks and enhanced commercial model.

PetroNor will soon commence interpretation on reprocessed seismic data in support of seeking a partner to join the Company in drilling one exploration well in this highly attractive acreage that is on trend with the Sangomar field, 30 km to the North in Senegal. PetroNor aims to participate in any future well at an equity level of 30-50% and is seeking partners to help test the exciting portfolio of potential drilling opportunities.

Review of Operations
Operational updates

Guinea-Bissau
2 & 4a & 5a

On 20 November 2020, the Company announced the purchase of SPE Guinea Bissau AB from Svenska Petroleum Exploration AB. The transaction received the required in-country approvals published in the Official Gazette of Guinea-Bissau (Boletim Oficial) on 20 April 2021. Subsequently, the Company has assumed the operatorship of the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences in Guinea-Bissau.

The licences have been recently extended for 3 years and are valid until 2 October 2023 maintaining the same attractive fiscal terms.

PetroNor intends to build on the excellent work of the previous Operator Svenska Petroleum Exploration Guinea Bissau, and maintain the momentum towards drilling built by the Partnership. The Atum-1x well will test a highly attractive and material prospect on the Sinapa licence, analogous to the Sangomar field in Senegal. Recently reprocessed seismic data will be interpreted as part of the ongoing evaluation of both licences and as preparation to drilling.

Senegal
ROP & SOSP

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

In May 2020, the Company agreed with the Government of Senegal to the halt of arbitration proceedings. On 5 April 2021, the Company announced that throughout the prolonged suspension period, the Company has made significant efforts to reach a mutually beneficial solution and has held numerous progressive meetings with the relevant authorities to no avail. While it is disappointing that a settlement could not be reached, the Board and its legal counsel remain wholly confident in PetroNor's legal position and look forward to progressing the Arbitration to an independent judgement.

Nigeria
OML-113 / The Aje Field

On 31 December 2020, PetroNor and Panoro Energy ASA ("Panoro") agreed to extend the completion long stop date for the previously announced purchase of Panoro's fully owned subsidiaries that hold 100% of the shares in Pan Petroleum Aje Limited ("Pan Aje") ("the Transaction"). The original long stop date was 31 December 2020, being the date by which authorisation of the Nigerian Department of Petroleum Resources and the consent of the Nigerian Minister of Petroleum Resources were required to have been received. The amended long stop date to complete the Transaction is now 30 June 2021.

The regulatory approval process in Nigeria is well underway at an advanced stage but has been delayed by the pandemic.

As previously announced, following completion of the Transaction, Panoro's intention is to declare a special dividend and distribute to its shareholders USD 10 million equivalent in PetroNor shares in order for Panoro shareholders to retain a direct listed exposure to Aje/OML-113.

Also in 2019, PetroNor entered into separate agreements with the OML-113 operator Yinka Folawiyo Petroleum ("YFP") to create a holding company to exploit the substantial gas and liquids reserves at Aje. The regulatory process for this agreement is aligned with the Transaction and is expected to be approved concurrently.

PetroNor and Panoro have also taken the opportunity to review the deferred contingent element of the Transaction, reflecting the changed macro-economic background since the original announcement in 2019. Under the original agreement, once PetroNor had recovered all its costs related to their future investments to bring Aje gas into production, the Company was to pay to Panoro additional consideration of USD 0.15 per 1,000 cubic feet of the natural gas sales, such additional consideration being capped at USD 25 million. The amended terms are for the consideration to be USD 0.10 per 1,000 cubic feet with the additional consideration being capped at USD 16.67 million.

PetroNor continued work to update the field development plan ("FDP") to expedite gas development and engaged with potential offtakers and partners. PetroNor will engage the JV partners after DPR approval.

Flare Gas

PetroNor E&P has jointly been working with Aragon (www.aragon.no) on developing a concept to capture flare gas. PetroNor and Aragon will convert pollution into clean energy. Today the world is flaring gas similar to an amount which could power all the cars in Europe or supply the African continent with electricity. Our consortium has been approved in Nigeria and is now in process to qualify for specific projects, PetroNor intends to expand its flare gas division as soon as we have one such project is developed as reference.

Result

The Board of Directors (the "Board") confirms that the annual financial statements have been prepared pursuant to the going concern assumption, and that this assumption was realistic at the balance sheet date. 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 and the realisation of assets and settlement of debt in normal operations.

The Group had USD 14.1 million in cash and bank balances as of 31 December 2020 (2019: USD 27.9 million).

PetroNor E&P Ltd 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

Key Consolidated Income Statement figures

Despite the ongoing impact of the pandemic, the Directors are pleased to report an EBITDA of USD 34.4 million for the year.

The Group managed to generate a net profit for the year of USD 11.2 million. However, the prior year loss was due to the accounting for a USD 19.4 million share-based payment expense in relation to the reverse takeover in August 2019. Once adjusted, the 2019 comparative would be a profit of USD 13.6 million.

These figures are due to the steady oil production of the PNGF Sud during the quarter and throughout the year that have come about from the workover program. In fact, since the Group first entered the licences in 2016, it has seen a 33% increase in the gross field production and the OPEX reduced by 58% from 25.0 USD/bbl to 10.4 USD/bbl in the same timeframe.

During 2020, there were only 7 liftings of oil, with a 12.7% increase on the 880,844 barrels lifted in 2019. Despite the depressed oil prices during 2020, the Group achieved an average selling price of 41 USD/bbl for the year, compared to the 65 USD/bbl in 2019. As a consequence, the group reports USD 67.5 million in revenue, a 34.3% decrease on 2019 USD 102.8 million.

Condensed Consolidated Balance Sheet

As at the year end, the Group reassessed the classification of the USD 21.3 million cash advanced to the Operator in Congo towards the Asset Retirement Obligation ("ARO") as a Non-Current Asset in a change to the presentation on the Q4-2020 interim report. Although in 2019, the contractor group agreed to refund previous surplus cash set aside for the ARO back into the operating cash pool, the current cash projection does not anticipate the same situation in the short term.

With the award of a new licence in The Gambia during the year, the Group has capitalised USD 3.0 million of intangible licence costs in relation to the new licence.

However as the past costs of the former A4 licence are allowed to be carried over to the new licence, the past cost pool far exceeds the carrying value of the asset as at 31 December 2020.

Throughout the year the Group maintained cost discipline, but a direct comparison of the administrative expenses for the Group between 2020 and 2019 is not possible. Due to the merger in August 2019, the 2019 comparative figures include the costs of the merger transaction, and 8 months of the former Cypriot group, whereas 2020 figures portray the costs of the enlarged group, despite significant cutbacks by management on overheads after the initial outbreak of the pandemic in the Spring of 2020.

Key Consolidated Income Statement figures
For the year ended 31 December

	2020 USD'000'000	2019 USD'000'000
Revenue from sales of petroleum products	**40.6**	57.5
Assignment of tax oil	**17.1**	29.9
Assignment of royalties	**9.8**	15.4
Revenue	**67.5**	102.8
EBITDA	**34.4**	49.1
Net profit/(loss)	**11.2**	(5,8)
Quantity of oil lifted (barrels)	**993,574**	880,844
Average selling price (USD/bbl)	**40.90**	65.25
Quantity of net oil produced after royalty, cost oil and tax oil (barrels)	**999,522**	860,769

Condensed Consolidated Balance Sheet
As at 31 December

	2020 USD'000'000	2019 USD'000'000
Current assets	**27.1**	55.9
Non-current assets	**51.9**	27.3
Total assets	**79.0**	83.2
Current liabilities	**26.4**	47.5
Non-current liabilities	**30.3**	14.4
Total liabilities	**56.7**	61.9
NET ASSETS	**22.3**	21.3
Capital and reserves attributable to owners of the parent	**7.9**	6.5
Non-controlling interests	**14.4**	14.7
TOTAL EQUITY	**22.3**	21.3

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 November 2022.

In Q3 2020, subsidiary company Hemla Africa Holding AS paid a USD 3.9 million dividend to minority interest and related party Symero Ltd ("Symero"). An amount equal to the dividend was immediately loaned to the Company by Symero with interest rates matching those already provided by the external financing from Rasamala and no security was provided for the loan. The maturity date is matched to the USD 15 million facilty from Rasmala.

Dividends paid or recommended

During the year no dividend was paid or recommended.

Risk Factors

Operational Risk Factors

The Group participates in oil and gas projects in countries in West Africa with emerging economies, such as Congo Brazzaville, Nigeria, The Gambia, Senegal and Guinea-Bissau.

Oil and gas exploration, development and production activities in such emerging markets are subject to significant political and economic uncertainties that may include, but are not limited to, the risk of war, terrorism, expropriation, nationalization, renegotiation or nullification of existing or future licences and contracts, changes in crude oil or natural gas pricing policies, changes in taxation and fiscal policies, imposition of currency controls and imposition of international sanctions. Travel bans, asset freezes or other sanctions may be imposed and have historically been imposed on countries in which the Group operates.

The Group has operations in countries with a low score on Transparency International's Corruption Perception Index, which implies that these countries are perceived as jurisdictions where there is a higher risk of corruption. Corrupt practices of third parties or anyone working for the Group or any of its affiliated parties, or allegations of such practices, may have a material adverse effect on the reputation, performance, financial condition, cash flow, prospects and/or results of the Group.

Business risk factors

The Group's business, results of operations, value of assets, reserves, cash flows, financial condition and access to capital depend significantly upon, and may be adversely affected by, the level of oil and gas prices, which are highly volatile.

The Group's revenues, cash flow, reserve estimates, profitability and rate of growth depend substantially on prevailing international and local prices of oil and gas. Prices for oil and gas may fluctuate substantially based on factors beyond the Group's control. Consequently, it is impossible to accurately predict future oil and gas price movements. Oil and gas prices are volatile and have witnessed significant changes in recent years, for many reasons including, but not limited to, changes in global and regional supply and demand, geopolitical uncertainty, availability of equipment and new technologies, weather conditions and natural disasters, terrorism as well as global and regional economic conditions. Sustained lower oil and gas prices or price declines may inter alia lead to a material decrease in the Group's net production revenues.

Currently, all of the Group's production comes from fields in the PNGF Sud asset in Congo Brazzaville. The Aje Transaction, if completed, will add a producing asset in Nigeria. Under any circumstance, the Group's operations and cash flow will be restricted to a very limited number of fields. If mechanical or technical problems, storms, shutdowns or other events or problems affect the current or future production of the current producing assets of the Group, or new fields coming into production, it may have direct and significant impact on a substantial portion of the Group's production and hence the Group's revenue, profits and financial position as a whole.

Rising climate change concerns have led and could lead to additional legal and/or regulatory measures which could result in project delays or cancellations, a decrease in demand for fossil fuels and additional compliance obligations, each of which could materially and adversely impact the Group's costs and/or revenues.

Risk Factors
Continued

In general, the Group's operations are subject to risks which are typical for the offshore oil and gas industry, all of which may have a material adverse effect on the Group's operations, cash flow and financial position, including but not limited to risks relating to:

- extension of existing licenses and permits, including whether any extensions will be subject to onerous conditions;
- delays, cost inflation, potential penalties and regulatory requirements with respect to exploration, development projects and production of hydrocarbons, and hydrocarbon production may be restricted, delayed or terminated due to a number of internal or external factors;
- decommissioning obligations and activities will incur costs and such costs may be in excess of expectations and budgets;
- third-party risk in terms of operators and partners and conflicts within a license group, such as the publicly know disputes within the Aje group;
- capacity constraints and cost inflation in the service sector and lack of availability of required services and equipment;
- restricted or limited access to necessary infrastructure or capacity booking for the transportation of oil and gas;
- restrictions with respect to offtake of oil and gas, including currency exchange regulations delaying or preventing timely settlement, offtaker credit risks as well as hostilities or acts of terrorism or war preventing offtake or impeding offtake and further production of crude.
- restrictions in the ability to sell or transfer license interests due to regulatory consent requirements, provisions in its joint operating agreements including pre-emption rights, if any, or applicable legislation;
- extremely complex and stringent regulations concerning health, safety and environment issues; and
- capsizing, environmental pollution to sea and air and other maritime disasters.

Financial risk factors

The overall risk management program seeks to minimize the potential adverse effects of unpredictable fluctuations in financial markets on financial performance, i.e., 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's activities are and will continue to be capital intensive. The Group expects future investments into existing and new hydrocarbon assets to be served by cash-flow from ongoing operations. However, it is also expected that the Group will look to raise debt to part-fund future growth. Such debt may not be timely available, or only be available at terms which are unattractive or makes investments less profitable than first expected. Restrictions in raising, or the unavailability of, debt may prevent the Group from growing as planned and may make the Group to forego or lose attractive opportunities, which in turn could have a negative impact on the Group's financial position and future prospects.

Equal 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-recognized 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
Staff	58%	50%
Board	Nil	+20%

Proportion of women

	Actual	Objective
Staff	36%	+20%
Executive management team	Nil	+20%
Board	29%	+40%

Share Capital

As at 31 December 2020, the Company's share capital consists entirely of 971,665,288 ordinary shares, with 99.7% of the Company's ordinary shares admitted for trading on Oslo Euronext Expand (Norway).

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 re-election. 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 himself for re-election. 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 re-election. In the event of equal voting at a director's 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. with the exception of senior management Chris Butler and Michael Barrett, 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 9 April 2021, after Tranche 1 of the post year end Private Placement the Company had 3,067 shareholders and 1,056,028,924 shares, with (99.7%) registered in the VPS. The table below shows the 20 largest shareholders in the Company:

#	Shareholder	Number of Shares	Per cent
1	Petromal LLC [1]	403,936,700	38.25%
2	NOR Energy AS [2]	143,555,857	13.59%
3	Gulshagen III AS [3]	45,000,000	4.26%
4	Gulshagen IV AS [3]	45,000,000	4.26%
5	Ambolt Invest AS	45,000,000	4.26%
6	Lenger Nedi Hagan AS	45,000,000	4.26%
7	ENG Group Soparfi S.A.	40,681,739	3.85%
8	Gulshagan II AS	37,607,768	3.56%
9	Enga Invest AS	19,692,746	1.86%
10	Pust For Livet AS	15,000,000	1.42%
11	Nordnet Bank AB	12,064,798	1.14%
12	Nordnet Livsforsikring AS	10,527,921	1.00%
13	Telinet Energi AS	9,768,377	0.93%
14	Omar Al-Qattan	7,645,454	0.72%
15	Leena Al-Qattan	7,645,454	0.72%
16	UBS Switzerland AG	6,570,123	0.62%
17	Sandberg JH AS	4,653,951	0.44%
18	Avanza Bank AB	4,399,286	0.42%
19	Danske Bank A/S	4,363,499	0.41%
20	Singh Baldev	4,051,424	0.38%
	Subtotal	**912,165,097**	**86.38%**
	Others	143,863,827	13.62%
	Total	**1,056,028,924**	**100.00%**

[1] Non-Executive Chairman, Mr. Alhomouz is the CEO of Petromal LLC.

[2] NOR Energy AS is a company controlled jointly by Mr. Søvold and Mr. Ludvigsen through indirect beneficial interests.

[3] Gulshagan III AS and Gulshagan IV AS are companies controlled by Mr. Søvold through an indirect beneficial interest.

Directors & Company Secretary

The Company has seven Directors on the Board. The Directors have various backgrounds and experience, offering the Group and the Company valuable perspectives on industrial, operational and financial issues. The qualifications and experience of the current directors is detailed on pages 24 & 25.

The former directors of the Company that held office during the year ended 31 December 2020 were as follows:

Knut Søvold
Executive Director and Chief Executive Officer

Qualifications
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, from 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, UK, 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 bopd. 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.

Mr. Søvold is a founding member of PetroNor, and although he has resigned from the Board, he remains fully commited to the Company as the Chief Executive Officer.

Gerhard Ludvigsen
Executive Director and Business Development Manager

Qualifications
BSc in Business Administration from Long Beach University, California, USA

Experience:
Mr. Ludvigsen is the founder of several companies in Norway, including PetroNor, and internationally within the oil and gas industry, as well as holding several board positions in start-up companies and being an advisor for a major securities house in Norway. Founded Hemla with AGR as co-founder with focus on oil and gas development, co-founded D&H Solutions AS with Daewoo Shipbuilding & Marine Engineering of South Korea for gas and LNG development with major international oil companies in Middle East and Africa. Mr. Ludvigsen has also been a director and major shareholder of FileFlow, developed by Fast Search & Transfer. Mr. Ludvigsen serves on the board of the charity foundation Power to Educate which supports education in emerging countries.

Stephen West
Executive Director and Chief Financial Officer

Qualifications
FCA (Australia & New Zealand)
ACA (England & Wales)
Bachelor of Commerce (Accounting and Business Law) - Curtin University of Technology

Experience
Mr. West has over 23 years of financial and corporate experience gained in public practice, oil and gas, mining and investment banking spanning Australia, United Kingdom, Europe, CIS and Africa. During his career Mr. West has held senior positions at Horwath Chartered Accountants, PricewaterhouseCoopers and Barclays Capital.

Dr. David King
Non-Executive Director

Qualifications
BSc (Hons) in Class 1 Physics/ Mathematics - University of East Anglia MSc and D.I.C. Geophysics - Imperial College London
PhD in Seismology - Australian National University

Experience
Dr. King is a professional geoscientist and has over 30 years' experience in oil and gas and other natural resources industries.

Timothy Turner
Non-Executive Director

Qualifications:
B.Bus, FCPA, CTA, Registered Company Auditor.

Experience
Mr. Turner has 25 years' experience in new ventures, capital raisings and general business consultancy, in addition to 15 years of experience in ASX listed junior resource-based exploration companies.

Directors & Company Secretary
Continued

Interests in Shares & Options
As at the date of this report:

Mr. Pace holds 1,498,938 shares.

Mr. Alhomouz has no personal interests in shares and options, but has influence over 403,936,700 shares as the CEO of significant shareholder Petromal LLC.

No other current board members hold shares or options.

Position as at resignation date:

NOR Energy AS, a company controlled jointly by Mr. Søvold and Mr. Ludvigsen through an indirect beneficial interest, held 444,237,596 shares when Mr. Søvold resigned as a Director on 29 May 2020.

On 31 January 2021, NOR Energy AS held 233,555,857 shares when Mr. Ludvigsen resigned as a Director. Furthermore, Mr. Ludvigsen held 45,000,000 shares through an indirect beneficial interest in Nedi Hagan AS. In addition 15,000,000 shares were held by Pust For Livet AS, a company controlled by immediate family of Mr. Ludvigsen.

On resignation Mr. West held 1,377,544 shares through an indirect beneficial interest in Cresthaven Investments Pty Ltd. Dr. King and Mr. Turner held 30,000 and 4,167 shares respectively on resignation.

Meetings of directors

The number of directors' meetings (including committees) held during the period where each director held office during the financial year and the number of meetings attended by each director is:

	Audit Committee Meetings		Directors' Meetings	
Director	Eligible to attend	Attended	Eligible to attend	Attended
Current				
E Alhomouz	-	-	11	10
J Pace	2	2	11	11
J Iskander	2	1	11	9
A Neuling	2	2	9	9
R Steinepreis	-	-	9	8
I Tybring-Gjedde	-	-	7	5
G Kielland	-	-	-	-
Former				
K Søvold	-	-	4	4
G Ludvigsen	-	-	7	7
S West	-	-	1	1
D King	-	-	-	-
T Turner	-	-	-	-

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, 10 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/her in his/her 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 (HSE)

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.

In light of the previously announced restructuring plans to install a Norwegian entity at the top of the Group and exit Australia, the Company is currently in the process of reassessing its set of operational guidelines and principles of Corporate Governance to adapt to a Norwegian legal jurisdiction.

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 license 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.

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 license conditions or any environmental regulations to which it is subject.

Corporate Social Responsibility/ Ethical Code of Conduct

The Company has a strong focus on CSR as well as an ethical code of conduct. The Company founders have established a separate CSR project, Power to Educate, and is supporting the CSR projects in the subsidiary in the Republic of Congo as well as the projects organized by the Operator in the PNGF Sud license group. During 2020, the Company registered as a supporting company with the Extractive Industries Transparency Initiative, EITI.

Payments to Governments

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 2020, 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. See Figure 01 below.

As the Company is waiting for Government approval of the Aje transaction, no payments were made in relation to this project during 2020.

Due to the arbitration status of the ROP and SOSP licences in Senegal, no payments were made in relation to these projects during 2020.

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.

Active legal corporate structure of the Group during 2020 is set out in Figure 02 below.

Figure 01

Project	Payments per project (USD'000)			
	Royalties	Oil tax	Other amounts[1]	Total
PNGF Sud	9,830	17,078	1,504	28,385
Congo Total	15,387	29,894	1,504	28,385
A4	Nil	Nil	2,903	2,903
The Gambia Total	Nil	Nil	2,903	2,903

[1] Other amounts includes payroll and other local taxes

Figure 02

Country of Incorporation Name	Main country of operations	Employees[1]	Interest paid or payable to a group entity USD'000
Australia			
PetroNor E&P Ltd	United Kingdom	-	-
Cyprus			
PetroNor E&P Ltd	Cyprus	1	1,563
Norway			
PetroNor E&P AS	Norway	5	-
Hemla Africa Holding AS	Norway	-	-
Republic of Congo			
Hemla E&P Congo S.A.	Republic of Congo	3	545
United Kingdom			
PetroNor E&P Services Ltd	United Kingdom	3	-
Nigeria			
PetroNor E&P Ltd	Nigeria	4	-
Cayman Islands			
African Petroleum Gambia Ltd	The Gambia	2	-
African Petroleum Senegal Ltd	Senegal	-	-
Senegal			
African Petroleum Senegal SAU	Senegal	2	-

[1] Average number of employees' during the year

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 2020	Number Under Option
11 January 2022	2.50	0.28	213,400
31 May 2022	7.75	0.88	1,176,070
Total			1,389,470

During the current year, no ordinary shares were issued on the exercise of options (2019: 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

Due to a breach of covenants under the loan agreement between Hemla Africa Holding AS ("HAH") and MGI International SA, the commercial court, Tribunal de Commerce de Pointe Noire, in Congo has awarded HAH 9,900 shares in Hemla E&P Congo SA ("HEPCO"), increasing HAH's share of HEPCO with 9.9%, equivalent to PetroNor increasing its indirect interest in PNGF Sud with 1.40% at a cost of approximately USD 4 million. As per Congolese law, the award can be challenged in a higher court, and if so the timing of such further appeal and any final outcome are uncertain.

On 29 January 2021, Gerhard Ludvigsen resigned as an Executive Director and was replaced on 1 February 2021 by Gro Kielland appointed as an Non-Executive Director.

A CPR update prepared by AGR Petroleum Services AS on the Company's PNGF Sud asset in Congo was released on 11 March 2021. The update represented an increase of approximately 28% and 49% for 2P and 2C respectively on a gross basis.

On 12 March 2021, the Company raised NOK 340 million of new equity through a Private Placement of 309,090,909 new shares in the Company. The Private Placement received strong interest from new investors, including institutional investors and private family offices in Norway and internationally. Petromal Sole Proprietorship LLC and related group companies ("Petromal"), the Company's main shareholder owning 38.28% of all issued and outstanding shares in the Company, subscribed for Offer Shares at the Offer Price for an amount of NOK 130.2 million, which corresponding to their 38.28% pro-rata share of the Private Placement.

The Private Placement will generate NOK 187.4 million (USD 22.1 million) in cash and NOK 152.6 million (USD 18.0 million) as in-kind consideration for contingent acquisition of all of Symero Limited's ("Symero") shares in Hemla Africa Holding AS ("HAH") (the "Symero Transaction"). Symero is owned by NOR Energy AS, a company owned by Knut Søvold, CEO of the Company, and Gerhard Ludvigsen.

The net cash proceeds from the Private Placement will be used to finance drilling of infill wells and other increased oil recovery initiatives on PNGF Sud and general corporate purposes. The Private Placement is divided into two tranches: Tranche 1 ("Tranche 1") consisting of Offer Shares for NOK 92.8 million have been allocated to existing and new investors, including Petromal. The remaining Offer Shares have been subscribed by and allocated to Symero (for an amount equal to NOK 152.6 million (USD 18 million) ("Tranche 2a") and Petromal (for an amount equal to NOK 94.6 million) in order to retain its ~38.28% ownership ("Tranche 2b").

The Company released a Notice of Meeting ("Notice") for an extraordinary general meeting ("EGM") to be held on the 4 May 2021, as the Symero Transaction is a related party transaction and subject to approval by ordinary resolution. An independent expert report was attached to the Notice as required pursuant the Australian Corporations Act.

The Company is contemplating to carry out a subsequent offering of new shares without tradable subscription rights of up to 60,000,000 new shares in the Company (equivalent to NOK 66 million) towards existing shareholders of the Company as of close of trading on Oslo Euronext Expand on 11 March 2021, shareholders of record on 15 March 2021. A combined prospectus for listing of the Offer Shares in Tranche 2a and Tranche 2b and for the offering of shares in the contemplated Subsequent Offering is expected to be published during May 2021.

On 5 April 2021, the Company announced that the arbitration proceedings for the Group's interests in Senegal were to resume despite numerous progressive meetings with the relevant authorities to reach a mutually beneficial solution.

On 26 April 2021, the Company announced that the regulatory approval for acquisition of SPE Guinea Bissau AB had been received, satisfying the condition precedent for completion.

Except for the above, the Company has not identified any events with significant accounting impacts that have occurred between the end of the reporting period and the date of this report.

Likely developments and expected results

With the governmental approval for the Sinapa and Esperança licences now received, the Company looks forward to the completion of the share purchase agreement for SPE Guinea Bissau AB in the coming week.

The Company is awaiting the governmental approval for Aje transaction and anticipates this to complete in the next few months.

The Company was pleased to announce post period two transactions to increase its net indirect interest in core asset PNGF Sud from 10.5% to 16.83%, as this will generate ~60% increase in PetroNor's PNGF Sud production and reserves with no impact on overhead costs;

Net production from PNGF Sud to increase from 2,385 barrels of oil per day ("bopd") to 3,850 bopd, based on 2020 average production;

Net 2P reserves as of Year-end 2020 increasing from 12.62 million to 20.23 million barrels of oil ("MMbbl");

After completion of Tranche 2a and 2b of the Private Placement, PetroNor will be in a robust financial position and fully funded for all sanctioned activities with significant flexibility to adjust its capital expenditure in a low oil price environment.

The infill drilling program on the Litanzi and Tchendo fields has been further delayed mainly due to the pandemic and is expected to restart in the H2-2021.

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 2020 has been received and can be found on page 43 of the annual report.

Non-audit services

Non-audit services were provided by the entity's auditor's BDO, as per Note 7b. 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, 29 April 2021

Eyas Alhomouz
Chairman of the Board

Gro Kielland
Director of the Board

Joseph Iskander
Director of the Board

Roger Steinepreis
Director of the Board

Jens Pace
Director of the Board

Alexander Neuling
Director of the Board

Ingvil Smines Tybring-Gjedde
Director of the Board

Financial Statements

Declaration of Independence by Phillip Murdoch to the Directors of Petronor E&P Limited

BDO

As lead auditor of PetroNor E&P Limited for the year ended 31 December 2020, 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, 29 April 2021

Consolidated Statement Profit or Loss and Other Comprehensive Income

	Note	For the year ended 31 December 2020 USD'000	For the year ended 31 December 2019 USD'000
Revenue	4	**67,543**	102,760
Cost of sales	5	**(25,885)**	(37,207)
Gross profit		**41,658**	65,553
Other operating income	6	**45**	9
Administrative expenses	7	**(12,376)**	(19,793)
Profit from operations		**29,327**	45,769
Finance expense	8	**(2,606)**	(1,822)
Foreign exchange gain / (loss)		**1,507**	(440)
Share based payment	23	**-**	(19,374)
Profit before tax		**28,228**	24,133
Tax expense	9	**(17,078)**	(29,894)
Profit/(Loss) for the year		**11,150**	(5,761)
Other Comprehensive income			
Exchange losses arising on translation of foreign operations		**(1,050)**	-
Total comprehensive income/(loss)		**10,100**	(5,761)
Profit/(Loss) for the year attributable to:			
Owners of the parent		**2,373**	(13,364)
Non-controlling interest		**8,777**	7,603
		11,150	(5,761)
Total comprehensive income/(loss) attributable to:			
Owners of the parent		**1,417**	(13,364)
Non-controlling interest		**8,683**	7,603
		10,100	(5,761)

Earnings per share attributable to members:		USD cents	USD cents
Basic profit/(loss) per share	10	**0.24**	(1.54)
Diluted profit/(loss) per share	10	**0.24**	(1.54)

The accompanying notes form part of these financial statements.

Consolidated Statement of Financial Position

	Note	As at 31 December 2020 USD'000	As at 31 December 2019 USD'000
Assets			
Current assets			
Inventories	11	**3,578**	3,233
Trade and other receivables	12	**9,397**	24,772
Cash and cash equivalents	13	**14,113**	27,891
		27,088	55,896
Non-current assets			
Property, plant and equipment	15	**23,483**	22,587
Intangible assets	16	**6,935**	4,691
Right-of-use assets	17	**212**	-
Other receivables	12	**21,260**	-
		51,890	27,278
Total assets		**78,978**	83,174
Liabilities			
Current liabilities			
Trade and other payables	18	**22,238**	34,602
Lease liability	17	**170**	-
Loans and borrowings	19	**4,000**	12,941
		26,408	47,543
Non-current liabilities			
Loans and borrowings	19	**14,912**	-
Lease liability	17	**55**	-
Provisions	20	**15,307**	14,373
		30,274	14,373
Total liabilities		**56,682**	61,916
NET ASSETS		**22,296**	21,258
Issued capital and reserves attributable to owners of the parent			
Share capital	21	**17,735**	17,735
Reserves	22	**(956)**	-
Retained earnings	22	**(8,853)**	(11,226)
		7,926	6,509
Non-controlling interests	24a	**14,370**	14,749
TOTAL EQUITY		**22,296**	21,258

The accompanying notes form part of these financial statements.
The financial statements were approved and authorised for issue by the Board of Directors on 29 April 2021.

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
For the year ended 31 December 2020							
BALANCE AT 1 JANUARY 2020		**17,735**	**-**	**-**	**(11,226)**	**14,749**	**21,258**
Profit for the year		**-**	**-**	**-**	**2,373**	**8,777**	**11,150**
Other comprehensive income:		**-**	**-**	**(956)**	**-**	**(94)**	**(1,050)**
Total comprehensive income for the year		**-**	**-**	**(956)**	**2,373**	**8,683**	**10,100**
Transactions with owners in their capacity as owners:							
Dividends paid during the year	22, 24a	**-**	**-**	**-**	**-**	**(9,062)**	**(9,062)**
BALANCE AT 31 DECEMBER 2020		**17,735**	**-**	**(956)**	**(8,853)**	**14,370**	**22,296**
For the year ended 31 December 2019							
BALANCE AT 1 JANUARY 2019		120	-	-	13,688	12,811	26,619
Profit/(loss) for the year		-	-	-	(13,364)	7,603	(5,761)
Other comprehensive income		-	-	-	-	-	-
Total comprehensive loss for the year		-	-	-	(13,364)	7,603	(5,761)
Transactions with owners in their capacity as owners:							
Issue of capital	21	17,615	-	-	-	-	17,615
Dividends paid during the year	22, 24a	-	-	-	(11,550)	(5,665)	(17,215)
BALANCE AT 31 DECEMBER 2019		17,735	-	-	(11,226)	14,749	21,258

The accompanying notes form part of these financial statements.

Consolidated Statement of Cash Flows

	Note	For the year ended 31 December 2020 USD'000	For the year ended 31 December 2019 USD'000
Cash flows from operating activities			
Profit for the year		**28,228**	24,133
Adjustments for:			
Depreciation and amortisation		**4,475**	3,323
Amortization of right-of-use asset		**169**	-
Unwinding of discount on decommissioning liability		**934**	877
Impairment of goodwill		**-**	9
Share-based payment expense		**-**	16,433
Net foreign exchange differences		**(1,050)**	-
		32,756	44,775
Decrease in trade and other receivables		**729**	6,724
Increase in advance against decommissioning cost		**(6,614)**	(3,286)
Increase in inventories		**(345)**	(663)
(Decrease)/increase in trade and other payables		**(12,363)**	24,950
Cash (used in)/generated from operations		**(18,593)**	27,725
Income taxes paid		**(17,078)**	(29,894)
Net cash flows from operating activities		**(2,915)**	42,606
Investing activities			
Purchases of property, plant and equipment		**(4,615)**	(12,466)
Purchases of intangible assets		**(3,007)**	-
Net cash flows from investing activities		**(7,622)**	(12,466)
Financing activities			
Issue of ordinary shares		**-**	1,182
Proceeds from loans and borrowings		**18,912**	12,917
Repayment of loans and borrowings		**(12,941)**	(7,059)
Repayment of principal portion of lease liability		**(131)**	-
Repayment of interest portion of lease liability		**(19)**	-
Dividends paid to non-controlling interest		**(9,062)**	(5,665)
Dividends paid		**-**	(11,550)
Net cash (used in)/from financing activities		**(3,241)**	(10,175)
Net increase/(decrease) in cash and cash equivalents		**(13,778)**	19,965
Cash and cash equivalents at beginning of year		**27,891**	7,926
Cash and cash equivalents at end of year	13	**14,113**	27,891

The accompanying notes form part of these financial statements.

Notes to the Consolidated Financial Statements

1. Corporate information
The financial report of the Company and its subsidiaries (together the "Group") for the year ended 31 December 2020 was authorised for issue in accordance with a resolution of the Directors on 29 April 2021.

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 Euronext Expand (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.

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 Limited, using the reverse acquisition rules for the merger that took place on 30 August 2019, Notes 3 & 23a.

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.

3. 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.

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 55 USD/bbl. The carrying amount of oil and gas properties and licenses at 31 December 2020 are shown in Note 15 and 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 15;
- 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 15);
- 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.

Notes to the Consolidated Financial Statements
Continued

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 9 and 30m.

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. Additional information is provided in Note 20.

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 had no book value in the accounting records of the Company on acquisition of African Petroleum Corporation Limited on 30 August 2019. 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.

4. Revenue

	2020 USD'000	2019 USD'000
Revenue from contracts from customers		
Revenue from sales of petroleum products[1]	**40,635**	57,479
Other Revenue		
Assignment of tax oil	**17,078**	29,894
Assignment of royalties	**9,830**	15,387
Total Revenue	**67,543**	102,760
Quantity of oil lifted (barrels)	**993,574**	880,844
Average selling price (USD/barrel)	**40.90**	65.25
Quantity of net oil produced after royalty, cost oil and tax oil (barrels)	**999,522**	860,769

[1] All revenue from the sales of petroleum products is generated from a single customer and recognised and transferred at a point in time.

Notes to the Consolidated Financial Statements
Continued

5. Cost of sales

	2020 USD'000	2019 USD'000
Operating expenses	**11,357**	18,292
Royalty	**9,830**	15,387
Depreciation and amortisation of oil and gas properties	**4,429**	3,231
Closing oil inventory	**269**	297
	25,885	37,207

6. Other operating income

	2020 USD'000	2019 USD'000
Other	**45**	9

7. Administrative expenses

	Note	2020 USD'000	2019 USD'000
Employee benefit expenses	7a	**5,108**	4,035
Termination benefits		**795**	-
Travelling expenses		**282**	1,047
Legal and professional expenses		**3,121**	6,502
Office rent		**87**	214
Related-party loan write-off	24d	**-**	5,305
Depreciation and amortization		**46**	-
Amortization on right-of-use assets		**169**	-
Other expenses		**2,768**	2,690
		12,376	19,793

7a. Employee benefit expenses

	2020 USD'000	2019 USD'000
Salaries	**4,486**	3,331
Short-term non-monetary benefits	**319**	308
Defined contribution pension cost	**104**	75
Share-based payment expense	**-**	-
Social-security contributions and similar taxes	**199**	321
	5,108	4,035

Notes to the Consolidated Financial Statements
Continued

7b. Auditors' remuneration

	2020 USD'000	2019 USD'000
Paid or payable to BDO		
Audit review of financial reports		
BDO Audit (WA) Pty Ltd	**90**	55
BDO Network firms	**76**	118
	166	173
Other non-assurance services		
BDO related practices	**40**	12
	206	185
Paid or payable to other audit firms		
Audit or review of financial reports	**40**	138
Other non-assurance services	**120**	141
	160	279

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

8. Finance expense

	Note	2020 USD'000	2019 USD'000
Unwinding of discount on decommissioning liability	20	**934**	877
Loan structuring fee		**150**	106
Finance cost on lease liabilities	17	**19**	-
Interest on loan	19	**1,493**	822
Other interest		**10**	17
		2,606	1,822

9. Tax expense

	2020 USD'000	2019 USD'000
Petroleum revenue tax expense		
Current income tax charge	**17,078**	29,894
Total tax expense reported in the consolidated statement of comprehensive income	**17,078**	29,894

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 4. There was no income tax expense in the other subsidiaries' jurisdictions nor in the parent's jurisdiction as these companies are in taxable loss position in both 2020 and 2019. Average effective tax rate for the year was 25% (2019: 29%) 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 2020 it is uncertain when future taxable amounts will be available to utilise those temporary differences and losses. As at 31 December 2020, the carried forward gross tax loss is USD 110 million (2019: USD 202 million).

Notes to the Consolidated Financial Statements
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10. Earnings per share

	2020 USD'000	2019 USD'000
Profit / (loss) attributable to ordinary shareholders		
Profit / (loss) from continuing operations attributable to the ordinary equity holders used in calculating basic / diluted profit per share	**2,373**	(13,364)
Profit / (loss) attributable to the ordinary equity holders used in calculating basic / diluted profit per share	**2,373**	(13,364)
	Number of shares	
Weighted average number of ordinary shares outstanding during the period used in the calculation of profit / (loss) per share		
Basic	**971,665,288**	868,020,990
Diluted	**974,229,968**	868,020,990

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 1,389,470 options as at 31 December 2020 (2019: 3,266,470). These options have not been included in the determination of basic loss per share because they are considered to be anti-dilutive.

11. Inventories

	2020 USD'000	2019 USD'000
Crude oil inventory	**689**	871
Materials and supplies	**2,889**	2,362
	3,578	3,233

Crude oil inventory is valued at cost of 17.79 USD/bbl (2019: 23.13 USD/bbl).

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.

12. Trade and other receivables

	Note	2020 USD'000	2019 USD'000
Recoverability less than one year			
Trade receivables		**5,408**	4,013
Due from related parties	24d	**3,639**	5,639
Advance against decommissioning cost [1]		**-**	14,646
Other receivables		**350**	474
		9,397	24,772
Recoverability more than one year			
Advance against decommissioning cost [1]		**21,260**	-
		21,260	-

[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 3.70 USD/bbl produced (2019: 3.50 USD/bbl). As at the year end, the Group reassessed the classification of the USD 21.3 million cash advanced to the Operator in Congo towards the decommissioning cost as a Non-Current Asset in a change to the presentation on the Q4 2020 interim report. Although the JV partnership in 2019 agreed to refund previous surplus cash set aside for the decommissioning cost back into the operating cash pool, the current cash projection does not anticipate the same situation in the next 12 months. Refer to Note 20 for further details on the decommissioning liability.

Notes to the Consolidated Financial Statements
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The Group measures the provision for impairment for trade receivables and amounts due from related parties at an amount equal to lifetime ECL. The ECL on trade receivables and amounts due from related parties are estimated using a provision matrix by reference to past default experience of the debtor and an analysis of the debtors' current financial position, adjusted for factors that are specific to the debtors' general economic conditions and forward looking elements of the industry in which the debtors operate and an assessment of both the current as well as the forecast direction of conditions at the reporting date. The trade receivables of USD 5.4 million is due from one customer only which is not past due yet. The Group considered significant increase in credit risk on its trade receivables and amounts due from related parties and estimates that no ECL is required as on 31 December 2020.

13. Cash and cash equivalents

	2020 USD'000	2019 USD'000
Cash in bank	**14,113**	26,988
Petty cash	**-**	-
Restricted cash	**-**	903
	14,113	27,891

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.

14. 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:

	2020 USD'000	2019 USD'000
Congo	**48,677**	27,182
Gambia	**3,007**	-
Nigeria	**1**	-
Norway	**205**	83
Senegal	**-**	2
UK	**-**	11
	51,890	27,278

Notes to the Consolidated Financial Statements
Continued

15. Property, plant, and equipment

	2020 USD'000	2019 USD'000
Production assets and equipment		
Cost		
At 1 January	**28,830**	16,464
Additions	**4,615**	12,375
Disposals	**-**	(9)
At 31 December	**33,445**	28,830
Depreciation		
At 1 January	**6,243**	3,884
Charge for the year	**3,719**	2,368
Depreciation on disposals	**-**	(9)
At 31 December	**9,962**	6,243
Net carrying amount		
At 31 December	**23,483**	22,587

Production assets and equipment cost includes the following:

	Note	2020 USD'000	2019 USD'000
Decommissioning costs	20	**11,899**	11,899
Oil & gas CAPEX		**21,546**	16,932
		33,445	28,830

16. Intangible assets
Licences and approval

	2020 USD'000	2019 USD'000
Cost		
At 1 January	**7,389**	7,389
Addition	**3,007**	-
At 31 December	**10,396**	7,389
Accumulated amortisation and impairment		
At 1 January	**2,698**	1,833
Amortisation	**763**	865
Impairment	**-**	-
At 31 December	**3,461**	2,698
Net carrying value		
At 1 January	**4,691**	5,556
At 31 December	**6,935**	4,691

Notes to the Consolidated Financial Statements
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Licence overview
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" and have an area of 482.28km². The operator of the licences is Perenco, and the carrying value as at 31 December 2020 is USD 3.9 million.

There were no indicators of impairment identified under IAS 36 and IAS 38 as at 31 December 2020 for the licence cost and property plant and equipment.

The Gambia
During the year the Company was awarded a new 30-year licence for the A4 licence, as part of the settlement agreement for the previous A1 and A4 licences. The A4 licence area is 1,376km² and is operated by Company subsidiary PetroNor E&P Gambia Ltd. As at 31 December 2020 the carrying value of the A4 licence is USD 3.0 million.

There were no indicators of impairment identified under IAS 38 as at 31 December 2020 for the licence cost.

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 combined licences cover an area of 15,796km2 and due to the arbitration process have nil carrying value in the financial statements as at 31 December 2020.

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	9.05	12.62	16.00

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.

Notes to the Consolidated Financial Statements

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17. Leases

	Right-of-use assets: Office building USD'000	Lease liabilities USD'000
At 1 January 2020	**-**	**-**
Additions	**381**	**337**
Amortization expense	**(169)**	**-**
Interest expense	**-**	**19**
Payments made	**-**	**(131)**
At 31 December 2020	**212**	**225**
Ageing of lease liabilities		
Current		**56**
Non-current		**170**

Amounts recognised in profit and loss

	31 December 2020 USD'000
Amortization expense on right-of-use assets	**169**
Interest expense on lease liabilities	**19**
Expense relating to short-term lease	**136**
	324

The total cash outflow for leases amount to USD 150,000 for the year.

18. Trade and other payables

	Note	2020 USD'000	2019 USD'000
Trade payables		**5,226**	14,809
Due to related parties	24d	**11,694**	13,784
Taxes and state payables		**348**	473
Other payables and accrued liabilities		**4,970**	5,536
		22,238	34,602

Notes to the Consolidated Financial Statements
Continued

19. Loans and borrowings

	2020 USD'000	2019 USD'000
At 1 January	**12,941**	7,083
Received	**18,912**	12,917
Principal repayment	**(12,941)**	(7,059)
Interest on loan accrued	**1,493**	822
Interest on loan paid	**(1,493)**	(822)
At 31 December	**18,912**	12,941

	2020 USD'000	2019 USD'000
Ageing of loans payable		
Current	**4,000**	12,941
Non-current	**14,912**	-
	18,912	12,941

During the year, the short-term debt facility of USD 12.9 Million from Rasmala (London and Dubai based investor group) was replaced with a USD 15 Million facility with 12 months grace period and final maturity date in October 2022. The loan is repaid in monthly instalments after the initial grace period and carries an interest rate of 9% plus one-month LIBOR payable monthly if the oil price is below 40 USD/bbl and 12% if the oil price is above 40 USD/bbl. The loan is secured against:
- The assignment of receivables by subsidiary company Hemla E&P Congo SA;
- Pledge over one of the bank accounts of subsidiary company Hemla Africa Holding AS;
- Pledge over one of the bank accounts of subsidiary company Hemla E&P Congo SA;
- Pledge over shares in subsidiary companies, Hemla Africa Holding AS and Hemla E&P Congo SA;
- Assignment of inter-company loan agreement between Hemla Africa Holding AS and Hemla E&P Congo SA; and
- Corporate guarantees by the parent company and its subsidiaries PetroNor E&P Ltd. Cyprus and Hemla E&P Congo SA.

On 28 September 2020, subsidiary company Hemla Africa Holding AS paid a USD 3.9 Million dividend to minority interest and related party Symero Ltd. An amount equal to the dividend was immediately loaned to the Parent Company by Symero Ltd with interest rates matching those already provided by external financing and no security was provided for the loan. The maturity date is matched to the USD 15 Million facility from Rasmala. All covenants were complied with and there were no breaches during the year for both loans payable to Rasmala and Symero.

20. Provisions

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 6.0% (2019: 6.5%) and an inflation rate of 1.6% (2019: 1.6%). The initial decommissioning liability (ARO) study was prepared internally by the operator Perenco and was presented to ARO Committee in 2018. The Company reassessed the applicable discount rate during 2020 based on the rates of government bonds issued in the Congo during the year. The Group reassessed the applicable discount rate during 2020 based on the rates of Congolese Government bonds issued in the Congo during the year. The impact of the change in discount factor was not considered material.

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:

	Note	2020 USD'000	2019 USD'000
At 1 January		**14,373**	13,496
Arising during the year		**-**	-
Unwinding of discount on decommissioning	8	**934**	877
At 31 December		**15,307**	14,373

Notes to the Consolidated Financial Statements
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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	
	2020	2019
Balance at the beginning of the year	**971,665,288**	-
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
Balance at end of the year	**971,665,288**	971,665,288

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

Reconciliation of movements in issued capital

	2020 USD'000	2019 USD'000
Balance at beginning of the year Fair value of issued share capital at beginning of the year	**17,735**	120
Issue of shares for reverse takeover1	-	17,615
Share capital at end of the year	**17,735**	17,735

[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.

Notes to the Consolidated Financial Statements
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22. Reserves
The movement in reserves are reflected in the statement of changes in equity.

Share-based payment reserve
The share-based payments reserve records options and share awards recognised as expenses, issued to employees, directors, and consultants. See note 23 for further details on share-based payments.

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.

Dividends
No dividends were declared during the year by the Parent Company. During 2019, the cash consideration of USD 11,549,988 for the reverse acquisition transaction was deemed and classified as dividend, Note 23.

23. Share based payments

	2020 USD'000	2019 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 Limited. 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 1.19 million 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 Limited 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 Limited. 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.

Notes to the Consolidated Financial Statements

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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[1]	**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)

	2019 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.

23b. Warrants

There were no warrants issued during the year.

During the previous 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 previous 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. 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.

Notes to the Consolidated Financial Statements

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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:

	2020		2019	
	Number of options[1]	Weighted average exercise price equivalent USD[1]	Number of options[1]	Weighted average exercise price equivalent USD[1]
Balance at beginning of the period	**3,266,470**	**0.53**	-	-
Awarded	**-**	**-**	-	-
Reverse takeover[2]	**-**	**-**	3,283,137	0.53
Lapsed	**(1,877,000)**	**0.34**	(16,667)	2.10
Forfeited during the year	**-**	**-**	-	-
Balance at end of the year	**1,389,470**	**0.81**	3,266,470	0.53
Exercisable at end of the year	**1,389,470**	**0.81**	3,266,470	0.53

[1] The USD equivalent weighted average exercise price as at 31 December 2020
[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 year was nil (2019: nil).

The share options outstanding at the end of the year had a weighted average remaining contractual life of 494 days (2019: 495 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:

			Proportion of effective ownership interest at 31 December	
Name	Country of incorporation	Principal place of business	2020	2019
PetroNor E&P Ltd	Cyprus	Cyprus	**100%**	100%
PetroNor E&P AS	Norway	Norway	**100%**	100%
PetroNor E&P Services Ltd	United Kingdom	United Kingdom	**100%**	100%
PetroNor E&P Nigeria Ltd	Nigeria	Nigeria	**100%**	100%
AJE Production AS	Norway	Norway	**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	Cayman Islands	United Kingdom	**100%**	100%
PetroNor E&P Gambia Ltd	Cayman Islands	The Gambia	**100%**	100%
African Petroleum Senegal Ltd	Cayman Islands	Senegal	**90%**	90%
African Petroleum Senegal SAU	Senegal	Senegal	**100%**	100%
APCL Gambia BV	Netherlands	The Gambia	**100%**	100%

Notes to the Consolidated Financial Statements
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Material non-controlling interests
Set out below is summarised financial information for each subsidiary that has non-controlling interests that are material to the group. The amounts disclosed for each subsidiary are before inter-company eliminations.

Summarised statement of financial position

	Hemla E&P Congo SA		Hemla Africa Holding AS	
	2020 USD' 000	2019 USD' 000	2020 USD' 000	2019 USD' 000
Current asset	**42,019**	38,106	**30,514**	26,291
Current liabilities	**19,054**	20,553	**4,026**	13,092
Current net assets	**22,965**	17,553	**26,488**	13,199
Non-current assets	**27,417**	27,182	**1,188**	1,188
Non-current liabilities	**21,986**	14,373	**11,000**	-
Non-current net assets/(liabilities)	**5,431**	12,809	**(9,812)**	1,188
Net assets	**28,396**	30,362	**16,676**	14,387
Accumulated NCI	**7,312**	7,818	**4,885**	4,214

Summarised statement of comprehensive income

	Hemla E&P Congo SA		Hemla Africa Holding AS	
	2020 USD' 000	2019 USD' 000	2020 USD' 000	2019 USD' 000
Revenue	**67,543**	102,760	**150**	-
Profit for the period	**18,034**	27,430	**15,957**	9,950
Other comprehensive income	**-**	-	**(316)**	-
Total comprehensive income for the year	**18,034**	27,430	**15,641**	9,950
Profit allocated to NCI	**8,556**	13,029	**4,674**	2,915
Dividends paid to NCI	**5,150**	5,665	**3,912**	-

Summarised cash flows

	Hemla E&P Congo SA		Hemla Africa Holding AS	
	2020 USD' 000	2019 USD' 000	2020 USD' 000	2019 USD' 000
Cash flows from operating activities	**8,245**	49,675	**2,877**	(1,608)
Cash flows from investing activities	**(4,606)**	(12,276)	**-**	-
Cash flows from financing activities	**(8,047)**	(22,000)	**(11,295)**	5,858
Net (decrease)/increase in cash and cash equivalents	**(4,408)**	15,399	**(8,418)**	4,250

Notes to the Consolidated Financial Statements
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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 and Company Secretary listed on page 9, and the following other key personnel:

Knut Søvold	Chief Executive Officer
Gerhard Ludvigsen	Business Development Manager
Claus Frimann-Dahl	Chief Technical Officer
Emad Sultan	Strategy and Contracts Manager
Michael Barrett	Exploration Manager
Chris Butler	Group Financial Controller

Post year-end remuneration

As at the approval date of this report the base salary and fees for the following members of key management is as follows:

Individual	Title	Group Entity	Base salary and fees/per annum	Total base salary and fees USD equivalent
E Alhomouz	Chairman [1]	PetroNor E&P AS	USD 240,000	360,000
	Non-Executive Director	Hemla E&P Congo SA	USD 120,000	
J Pace	Non-Executive Director	PetroNor E&P Ltd	NOK 250,000	30,150
J Iskander	Non-Executive Director		Nil	Nil
A Neuling	Non-Executive Director	PetroNor E&P Ltd	AUD 48,000	37,300
R Steinepreis	Non-Executive Director	PetroNor E&P Ltd	AUD 48,000	37,300
I Tybring-Gjedde	Non-Executive Director	PetroNor E&P AS	NOK 250,000	30,150
G Kielland	Non-Executive Director	PetroNor E&P AS	NOK 250,000	30,150
K Søvold	Chief Executive Officer	PetroNor E&P AS	NOK 1,860,000	290,300
	Non-Executive Director	Hemla E&P Congo SA	USD 66,000	
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	186,900
M Barrett	Exploration Manager	PetroNor E&P Services Ltd	GBP 150,000	208,350
C Butler	Group Financial Controller	PetroNor E&P Services Ltd	GBP 115,000	159,700
A Hicks	Company Secretary	PetroNor E&P Ltd	AUD 24,000	18,650

[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 28 April 2021
NOK 1.00 : USD 0.12060
GBP 1.00 : USD 1.3890

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Remuneration of key management personnel

2020	Designation	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Termination fees USD	Total USD
Management						
K Søvold	Exec Director & CEO	254,107	832	22,114	-	277,053
J Pace [1]	Exec Director & CEO	83,039	1,318	-	448,618	532,975
S West [2]	Exec Director & CFO	58,884	2,030	5,888	346,077	412,879
G Ludvigsen	Exec Director & Business Development Manager	254,107	832	23,471	-	278,410
C Frimann-Dahl	Chief Technical Officer	200,432	747	18,962	-	220,141
M Barrett	Exploration Manager	246,595	2,131	-	-	248,726
C Butler	Group Financial Controller	147,766	5,766	14,777	-	168,309
E Sultan	Strategy & Contracts Manager Related party fees [3]	232,500	-	-	-	232,500
A Hicks	Company Secretary	23,995	-	-	-	23,995
		1,501,425	**13,656**	**85,212**	**794,695**	**2,394,988**
Directors' remuneration for PetroNor E&P Ltd Australia						
E Alhomouz	Non-Exec Chairman Related party fees [3]	255,000	-	-	-	255,000
J Iskander	Non-Exec Director	-	-	-	-	-
Jens Pace [1]	Non-Exec Director	-	-	-	-	-
A Neuling [4]	Non-Exec Director	24,403	-	-	-	24,403
R Steinepreis [4]	Non-Exec Director	22,600	-	-	-	22,600
I Smines Tybring Gjedde [5]	Non-Exec Director	17,565	-	-	-	17,565
T Turner [6]	Non-Exec Director	1,760	-	-	-	1,760
D King [7]	Non-Exec Director	(3,000)	-	-	-	(3,000)
		318,328	**-**	**-**	**-**	**318,328**
Directors' remuneration for subsidiaries						
E Alhomouz	Non-Exec for HEPCO	120,000	-	-	-	120,000
K Søvold	Non-Exec for HEPCO	66,000	-	-	-	66,000
G Ludvigsen	Non-Exec for HEPCO	66,000	-	-	-	66,000
		252,000	-	-	-	**252,000**
TOTAL		**2,071,753**	**13,656**	**85,212**	**794,695**	**2,965,316**

[1] On 29 February 2020, Mr. Pace resigned as CEO but remained on the board as a Non-Exec Director. Mr. Pace agreed to waive his Non-Exec Director remuneration for one year in recognition of the termination fees agreed for resigning as CEO.
[2] Resigned 29 February 2020
[3] 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.
[4] Appointed 6 April 2020
[5] Appointed 29 May 2020
[6] Resigned 8 February 2020
[7] Resigned 1 February 2020

Notes to the Consolidated Financial Statements
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2019	Designation	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Termination fees 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	-	-	125,997
C Butler [1]	Group Financial Controller	48,239	2,209	4,824	-	55,272
E Sultan [2]	Strategy & Contracts Manager Related party fees [2]	301,239	-	-	-	301,239
A Hicks [1]	Company Secretary	5,466	-	-	-	5,466
		1,698,756	**8,280**	**66,329**	**-**	**1,773,366**
Directors' remuneration for PetroNor E&P Ltd Australia						
E Alhomouz	Non-Exec Chairman Related party fees [2]	361,488	-	-	-	361,488
J Iskander [3]	Non-Exec Director	-	-	-	-	-
T Turner [1]	Non-Exec Director	5,456	-	-	-	5,456
D King [1]	Non-Exec Director	12,000	-	-	-	12,000
B Moe [1]	Non-Exec Director	11,000	-	-	-	11,000
		389,944	**-**	**-**	**-**	**389,944**
Directors' remuneration for subsidiaries						
E Alhomouz	Non-Exec for HEPCO	120,000	-	-	-	120,000
K Søvold	Non-Exec for HEPCO	66,000	-	-	-	66,000
G Ludvigsen	Non-Exec for HEPCO	66,000	-	-	-	66,000
A Georghiou [5] [6]	Non-Exec for PN Cyprus	6,143	-	-	-	6,143
H Marshad [5]	Non-Exec for PN Cyprus	5,500	-	-	-	5,500
N Kouyialis [5] [6]	Non-Exec for PN Cyprus	6,250	-	-	-	6,250
		269,893	**-**	**-**	**-**	**269,893**
TOTAL		**2,358,593**	**8,280**	**66,329**	**-**	**2,433,203**

[1] Remuneration from 30 August 2019 to 31 December 2019, i.e., after completion of reverse takeover
[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.
[4] Appointed 30 August 2019 and agreed to waive his remuneration as Non- Executive Director as appointed by Petromal LLC
[5] Appointed 17 April 2019
[6] Individual ceased to be part of key management upon completion of reverse takeover on 30 August 2019

During 2020, Employer's social taxes of USD 204,700 (2019: USD 169,118) were payable for the key management remuneration.

Notes to the Consolidated Financial Statements
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Share holdings by Directors and other Key Management Personnel

	Balance 1 January 2020	Shares purchased	Granted as remuneration	Net change other	Balance 31 December 2020
K Søvold jointly with G Ludvigsen [1]	444,237,596	-	-	(210,681,739)	233,555,857
K Søvold [2]	-	-	-	45,000,000	45,000,000
G Ludvigsen [3]	-	-	-	60,000,000	60,000,000
J Pace	1,498,938	-	-	-	1,498,938
S West [4]	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)	-
T Turner	4,167	-	-	(4,167)	-
	448,584,218	**-**	**-**	**(107,093,460)**	**341,490,758**

[1] Shares are held by NOR Energy AS, a company controlled jointly by K Søvold and G Ludvigsen through an indirect beneficial interest.
[2] Shares are held by Gulshagan III AS, a company controlled by K Søvold through an indirect beneficial interest.
[3] 45,000,000 shares are held by Nedi Hagan AS, a company controlled by G Ludvigsen through an indirect beneficial interest. A further 15,000,000 shares are held by Pust for Livet A, a company controlled by a close associate of G Ludvigsen.
[4] Shares are held by Cresthaven Pty Ltd, a company controlled by S West through an indirect beneficial interest.

As at 31 December 2020, Eyas Alhomouz held no shares personally but holds influence over 371,961,246 shares (2019: 371,961,246 shares) as the CEO of significant shareholder Petromal LLC.

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

No warrants or options were held by Directors and other Key Management Personnel during the current year.

24c. Significant Shareholders

Shareholder	Place of incorporation	31 December 2020 Ownership	31 December 2019 Ownership
Petromal LLC – Sole Proprietorship LLC	UAE	**38.28%**	38.28%
NOR Energy AS	Norway	**24.03%**	45.72%

After the year end, a further 84,363,636 shares were issued for a private placement. Plus, NOR Energy AS divested another 90,000,000 shares, with 45,000,000 to a company controlled by K Søvold and 45,000,000 to a company controlled by G Ludvigsen. Consequently, at the date of signing this report, NOR Energy AS have 13.59% ownership. But if as expected, the Symero Transaction is completed during May 2021, NOR Energy AS will increase their effective to 22.04% through their control of Symero Ltd.

Notes to the Consolidated Financial Statements
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24d. Transactions and period-end balances with related parties
Transactions with related parties included in the consolidated statement of comprehensive income:

	2020 USD'000	2019 USD'000
Nor Energy AS subsidiary company – loan write-off [1]	-	5,305
Nor Energy AS – charge back of expenses	-	103
Petromal – Sole Proprietorship LLC	587	1,088
Administrative expenses	**587**	6,496

[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.

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

	2020 USD'000	2019 USD'000
Loan receivable from MGI International S.A. [1]	3,639	5,639
Total receivables from related parties (Note 12)	3,639	5,639
Other payable to Nor Energy AS	3,378	5,783
Other payable to Petromal – Sole Proprietorship LLC	2,030	4,534
Other payable to Symero Ltd.	108	-
Other payable to MGI International S.A.	6,178	3,467
Total payables to related parties (Note 18)	**11,694**	13,784
Loan payable Symero Ltd	3,912	-
Loan payable to related parties (Note 19)	3,912	-

[1] During 2018, 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 program. The Group has various financial assets such as accounts receivable and cash.

It is, and has been throughout the year ending 31 December 2020, 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.

The sensitivity has been prepared for periods ending 31 December 2020 using the amounts of debt and other financial assets and liabilities held as at those reporting dates.

Notes to the Consolidated Financial Statements
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Credit risk
Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. As at 31 December 2020, the Group's maximum exposure to credit risk without taking into account any collateral held or other credit enhancements, which will cause a financial loss to the Group due to failure to discharge an obligation by the counterparties and financial guarantees provided by the Group arises from the carrying amount of the respective recognised financial assets as stated in the statement of financial position.

To minimise credit risk, the Group has tasked its management to develop and maintain the Group's credit risk gradings to categorise exposures according to their degree of risk of default. The credit rating information is supplied by independent rating agencies where available and, if not available, the management uses other publicly available financial information and the Group's own trading records to rate its major customers and other debtors. The Group's exposure and the credit ratings of its counterparties are continuously monitored, and the aggregate value of transactions concluded is spread amongst approved counterparties.

The Company's current credit risk grading framework comprises the following categories:

Category	Description	Basis for recognising expected credit losses
Performing	The counterparty has a low risk of default and does not have any past-due amounts	12-month ECL
Doubtful	Amount is >30 days past due or there has been a significant increase in credit risk since initial recognition	Lifetime ECL – not credit-impaired
In default	Amount is >90 days past due or there is evidence indicating the asset is credit-impaired	Lifetime ECL – credit-impaired
Write-off	There is evidence indicating that the debtor is in severe financial difficulty and the Company has no realistic prospect of recovery	Amount is written off

The tables below detail the credit quality of the Company's financial assets as well as the Company's maximum exposure to credit risk by credit risk rating grades.

	Notes	External credit rating	Internal credit rating	12-month or lifetime ECL	Gross carrying amount USD'000	Loss allowance USD'000	Net carrying amount USD'000
31 December 2020							
Trade receivables	12	N/a	(i)	Lifetime ECL	**5,408**	**-**	**5,408**
Due from related parties	12, 24d	N/a	-	Lifetime ECL	**3,639**	**-**	**3,639**
Advance against decommissioning cost	12	N/a	-	Lifetime ECL	**21,260**	**-**	**21,260**
Cash and cash equivalents	13	Aa3/B	N/a	12-month ECL	**14,113**	**-**	**14,113**
31 December 2019							
Trade receivables		N/a	(i)	Lifetime ECL	4,013	-	4,013
Due from related parties		N/a	-	Lifetime ECL	5,639	-	5,639
Advance against decommissioning cost		N/a	-	Lifetime ECL	14,464	-	14,464
Cash and cash equivalents		Aa3/B	N/a	12-month ECL	27,891	-	27,891

(i) For trade receivables and amounts due from related parties, the Group has applied the simplified approach in IFRS 9 to measure the loss allowance at lifetime ECL. The expected credit losses are estimated using a provision matrix by reference to past default experience of the debtor and an analysis of the debtor's current financial position, adjusted for factors that are specific to the debtors, general economic conditions of the industry in which the debtors operate and an assessment of both the current as well as the forecast direction of conditions at the reporting date.

Notes to the Consolidated Financial Statements
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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 2020 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 2020							
Trade accounts payable	19	**544**	**479**	**4,203**	**-**	**-**	**5,226**
Amounts due to related parties	24d	**11,986**	**-**	**-**	**-**	**-**	**11,986**
Loan payable	20	**-**	**-**	**-**	**4,000**	**14,912**	**18,912**
		12,530	**479**	**4,203**	**4,000**	**14,912**	**36,124**

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	19	616	1,580	2,483	10,130	-	14,809
Amounts due to related parties	24d	13,784	-	-	-	-	13,784
Loan payable	20	-	588	1,176	11,176	-	12,941
		14,400	2,168	3,659	21,306	-	41,535

The Company had USD 14.1 million (2019: 27.0 million) in unrestricted cash as of 31 December 2020. 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 2020		31 December 2020	
	+150bp USD'000	-150bp USD'000	+150bp USD'000	-150bp USD'000
Loans payable	**(284)**	**284**	(194)	194

Notes to the Consolidated Financial Statements
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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 2020		31 December 2019	
	+20% USD'000	-20% USD'000	+20% USD'000	-20% USD'000
USD vs NOK				
Cash	**58**	**(58)**	45	(45)
Receivables	**61**	**(61)**	99	(99)
Payables	**(25)**	**25**	(246)	246
	94	**(94)**	(102)	102
USD vs GBP				
Cash	**4**	**(4)**	3	(3)
Receivables	**2**	**(2)**	11	(11)
Payables	**(42)**	**42**	(119)	119
	(36)	**36**	(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, loans payable, 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.

Notes to the Consolidated Financial Statements

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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

	2020 USD'000	2019 USD'000
Within one year [1]	**40,000**	40,000

[1] The commitment in Senegal includes USD 40 million 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.

Contingencies

There are no contingencies as of the year end (2019: nil).

28. Parent entity financial information

i. Summary financial information

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

	2020 USD'000	2019 USD'000
Statement of financial position		
Current assets	**20,149**	16,403
Non-current assets	**104,027**	104,027
Total assets	**124,176**	120,430
Current liabilities	**(15,971)**	(15,559)
Non-current liabilities	**(3,912)**	-
Total liabilities	**(19,883)**	(15,559)
Net Assets	**104,293**	104,871
Shareholders' equity		
Issued capital	**1,130,901**	1,130,901
Reserves	**29,391**	29,391
Accumulated losses	**(1,055,998)**	(1,055,421)
	104,293	104,871
Net loss for the year	**(577)**	(1,357)
Total comprehensive loss	**(577)**	(1,357)

ii. Guarantees entered into by the parent entity

In support of various subsidiaries, the listed top company PetroNor E&P Limited has provided the following guarantees:

PetroNor E&P Gambia Ltd is required to place a performance bond of USD 1 million in favour of the Gambian Government.

PetroNor E&P Services Ltd employed the former CFO and CEO of the group, Stephen West and Jens Pace respectively. Termination benefits have been guaranteed amounting to USD 273,760 as at 31 December 2020.

During the year, Hemla Africa Holding AS entered into a loan agreement with Acqua Diversified Holdings SPC for USD 15 Million. The Parent Company has provided a corporate guarantee to Acqua Diversified Holdings SPC for the repayment of this loan. Amount outstanding as of 31 December 2020 was USD 15 Million.

No financial guarantees in respect of bank overdrafts, decommissioning liabilities and loans of subsidiaries were provided in the year ended 31 December 2019.

Notes to the Consolidated Financial Statements
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29. Events subsequent to reporting date
Due to a breach of covenants under the loan agreement between Hemla Africa Holding AS ("HAH") and MGI International SA, the commercial court, Tribunal de Commerce de Pointe Noire, in Congo has awarded HAH 9,900 shares in Hemla E&P Congo SA ("HEPCO"), increasing HAH's share of HEPCO with 9.9%, equivalent to PetroNor increasing its indirect interest in PNGF Sud with 1.40% at a cost of approximately USD 4 million. As per Congolese law, the award can be challenged in a higher court, and if so the timing of such further appeal and any final outcome are uncertain.

On 29 January 2021, Gerhard Ludvigsen resigned as an Executive Director and was replaced on 1 February 2021 by Gro Kielland appointed as a Non-Executive Director.

A CPR update prepared by AGR Petroleum Services AS on the Company's PNGF Sud asset in Congo was released on 11 March 2021. The update represented an increase of approximately 28% and 49% for 2P and 2C respectively on a gross basis.

On 12 March 2021, the Company raised NOK 340 million of new equity through a Private Placement of 309,090,909 new shares in the Company. The Private Placement received strong interest from new investors, including institutional investors and private family offices in Norway and internationally. Petromal Sole Proprietorship LLC and related group companies ("Petromal"), the Company's main shareholder owning 38.28% of all issued and outstanding shares in the Company, subscribed for Offer Shares at the Offer Price for an amount of NOK 130.2 million, which corresponds to their 38.28% pro-rata share of the Private Placement.

The Private Placement will generate NOK 187.4 million (USD 22.1 million) in cash and NOK 152.6 million (USD 18.0 million) as in-kind consideration for contingent acquisition of all of Symero Limited's ("Symero") shares in Hemla Africa Holding AS ("HAH") (the "Symero Transaction"). Symero is owned by NOR Energy AS, a company owned by Knut Søvold, CEO of the Company, and Gerhard Ludvigsen.

The net cash proceeds from the Private Placement will be used to finance drilling of infill wells and other increased oil recovery initiatives on PNGF Sud and general corporate purposes. The Private Placement is divided into two tranches: Tranche 1 ("Tranche 1") consisting of Offer Shares for NOK 92.8 million have been allocated to existing and new investors, including Petromal. The remaining Offer Shares have been subscribed by and allocated to Symero (for an amount equal to NOK 152.6 million (USD 18 million) ("Tranche 2a") and Petromal (for an amount equal to NOK 94.6 million) in order to retain its ~38.28% ownership ("Tranche 2b").

The Company released a Notice of Meeting for an EGM to be held on the 4 May 2021, as the Symero Transaction is a related party transaction and subject to approval by ordinary resolution. An independent expert report was attached to the Notice as required pursuant the Australian Corporations Act.

The Company is contemplating to carry out a subsequent offering of new shares without tradable subscription rights of up to 60,000,000 new shares in the Company (equivalent to NOK 66 million) towards existing shareholders of the Company as of close of trading on Oslo Euronext Expand on 11 March 2021, shareholders of record on 15 March 2021. A combined prospectus for listing of the Offer Shares in Tranche 2a and Tranche 2b and for the offering of shares in the contemplated Subsequent Offering is expected to be published during May 2021.

On 5 April 2021, the Company announced that the arbitration proceedings for the Group's interests in Senegal were to resume despite numerous progressive meetings with the relevant authorities to reach a mutually beneficial solution.

On 26 April 2021, the Company announced that the regulatory approval for acquisition of SPE Guinea Bissau AB had been received, satisfying the condition precedent for completion.

Except for the above, the Company has not identified any events with significant accounting impacts that have occurred between the end of the reporting period and the date of this report.

30. 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.

Notes to the Consolidated Financial Statements
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30a. 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 2020. The Group has not elected to early adopt any new standards or amendments.

The Group applied AASB 16 Leases for the first time. The nature and effect of the changes as a result of adoption of this new accounting standard is described below.

AASB 16 Leases
AASB 16 supersedes AASB 117 Leases, Interpretation 4 Determining whether an Arrangement contains a Lease, Interpretation 115 Operating Leases-Incentives and Interpretation 127 Evaluating the Substance of Transactions Involving the Legal Form of a Lease. The standard sets out the principles for the recognition, measurement, presentation, and disclosure of leases and requires lessees to account for most leases on the balance sheet.

Lessor accounting under AASB 16 is substantially unchanged from AASB 117. Lessors will continue to classify leases as either operating or finance leases using similar principles as in AASB 117. Therefore, AASB 16 did not have an impact for leases where the Group is the lessor.

The Group has opted for the simplified modified retrospective application permitted by AASB 16 upon adoption of the new standard. The Company does not restate any comparative information. During first time application of AASB 16 to operating leases, the right of use have been measured at the amount of lease liability adjusted by the amount of any prepaid or accrued payments recognised in the statement of financial position immediately before the date of initial application.

Impact of the new definition of lease
The Group has made use of the practical expedient available on transition to AASB 16 not to reassess whether a contract is or contains a lease. Accordingly, the definition of a lease in accordance with AASB 117 will continue to be applied to leases entered or modified before 1 January 2019. The change in definition of a lease mainly relates to the concept of control. AASB 16 determines whether a contract contains a lease on the basis of whether the customer has the right to control the use of an identified asset for a period of time in exchange for consideration. The Group applies the definition of a lease and related guidance set out in AASB 16 to all lease contracts entered into or modified on or after 1 January 2019 (whether it is a lessor or a lessee in the lease contract). In preparation for the first-time application of AASB 16, the Group has carried out an implementation project. The project has shown that the new definition in AASB 16 will not change significantly the scope of contracts that meet the definition of a lease for the Group.

Impact on Lessee Accounting
Former operating leases
AASB 16 changes how the Group accounts for leases previously classified as operating leases under AASB 117, which were off-balance-sheet. Applying AASB 16, for all leases (except as noted below), the Group:
- recognises right-of-use assets and lease liabilities in the statement of financial position, initially measured at the present value of future lease payments;
- recognises depreciation of right-of-use assets and interest on lease liabilities in the statement of profit or loss; and
- separates the total amount of cash paid into a principal portion (presented within financing activities) and interest (presented within operating activities) in the statement of cash flows.

Lease incentives (e.g., free rent period) are recognised as part of the measurement of the right-of-use assets and lease liabilities whereas under AASB 17 they resulted in the recognition of a lease incentive liability, amortised as a reduction of rental expense on a straight-line basis.

Under AASB 16, right-of-use assets are tested for impairment in accordance with AASB 136 Impairment of Assets. This replaces the previous requirement to recognise a provision for onerous lease contracts. For short term leases (lease term of 12 months or less) and leases of low-value assets (such as personal computers and office furniture), the Company has opted to recognise a lease expense on a straight-line basis as permitted by AASB 16. This expense is presented within other expenses in the statement of profit or loss.

The main difference between AASB 16 and AASB 117 with respect to assets formerly held under a finance lease is the measurement of residual value guarantees provided by a lessee to a lessor. AASB 16 requires that the Company recognises as part of its lease liability only the amount expected to be payable under a residual value guarantee, rather than the maximum amount guaranteed as required by AASB 117. This change did not have a material effect on the Group's financial statements.

Notes to the Consolidated Financial Statements
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Financial impact of initial application of AASB 16
The Directors note that the impact of the initial application of AASB 16 is not material to the overall financials statement of the Group.

The application of AASB 16 to leases previously classified as operating leases under AASB 117 resulted in the recognition of right-of-use assets and leases liabilities. It resulted in a decrease in other expense and an increase in depreciation and amortisation expense and in interest expense.

The lease incentives liability previously recognised with respect to operating leases has been derecognised and the amount factored in the measurement of the right-of-use assets and lease liabilities.

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 2020-5 Amendments to AASs – Insurance Contracts	1 Jan 2021
AASB 2020-8 Amendments to AASs – Interest Rate Benchmark Reform – Phase 2	1 Jan 2021
AASB 2020-7 Amendments to AASs – Covid-19-Related Rent Concessions: Tier 2 Disclosures	1 Jul 2021
AASB 1060 General Purpose Financial Statements – Simplified Disclosures for For-Profit and Not- for-Profit Tier 2 Entities	1 Jul 2021
AASB 2020-2 Amendments to AASs – Removal of Special Purpose Financial Statements for Certain For-Profit Private Sector Entities	1 Jul 2021
AASB 2020-3 Amendments to AASs – Annual Improvements 2018–2020 and Other Amendments ● Amendment to AASB 1, Subsidiary as a First-time Adopter ● Amendments to AASB 3, Reference to the Conceptual Framework ● Amendment to AASB 9, Fees in the '10 per cent' Test for Derecognition of Financial Liabilities ● Amendments to AASB 116, Property, Plant and Equipment: Proceeds before Intended Use ● Amendments to AASB 137, Onerous Contracts – Cost of Fulfilling a Contract ● Amendment to AASB 141, Taxation in Fair Value Measurements	1 Jan 2022
AASB 2014-10 Amendments to AASs – Sale or Contribution of Assets between an Investor and its Associate or Joint Venture	1 Jan 2022
AASB 17 Insurance Contracts	1 Jan 2023
AASB 2020-1 Amendments to AASs – Classification of Liabilities as Current or Non-current	1 Jan 2023

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

30b. 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 2020 (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 (i.e., 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.

Notes to the Consolidated Financial Statements

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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.

30c 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".

30d 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.

30e. 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.

Notes to the Consolidated Financial Statements
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30f. 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.

30g. 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.

30h. 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%

Notes to the Consolidated Financial Statements
Continued

30i. 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.

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.

30j. 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.

30k. 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.

ii. Other revenue
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.

iii. 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.

iv. 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.

Notes to the Consolidated Financial Statements
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30l. Leases

The Group as lessee

The Group assesses whether contract is or contains a lease, at inception of the contract. The Group recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low value assets. For these leases, the Group recognises the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, the Group uses its incremental borrowing rate.

Lease payments included in the measurement of the lease liability comprise:
- fixed lease payments (including in-substance fixed payments), less any lease incentives;
- variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date;
- the amount expected to be payable by the lessee under residual value guarantees;
- the exercise price of purchase options, if the lessee is reasonably certain to exercise the options; and
- payments of penalties for terminating the lease, if the lease term reflects the exercise of an option to terminate the lease.

The lease liability is presented as a separate line item in the statement of financial position.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability (using effective interest method) and by reducing the carrying amount to reflect the lease payments made.

The Group remeasures the lease liability (and makes a corresponding adjustment to the related right-of-use asset) whenever:
- the lease term has changed or there is a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.
- the lease payments change due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which cases the lease liability is remeasured by discounting the revised lease payments using the initial discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revise discount rate is used).
- a lease contract is modified, and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.

The Group did not make any such adjustments during the periods presented.

The right-of-use assets are depreciated over the shorter period of lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use of asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

The right-of-use of assets are presented as a separate line in the statement of financial position.

The Group applies AASB 136 to determine whether a right-of-use asset is impaired and accounts for an identified impairment loss as described in the 'Property, plant and equipment' policy.

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognised as an expense in the period in which the event or condition that triggers those payments occurs and are included in the line 'Administrative expenses' in the statement of profit or loss.

The Group as lessor

The Group enters into lease agreements as a lessor with respect to some of its investment properties.

Leases for which the Group is a lessor are classified as finance or operating leases. Whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee, the contract is classified as a finance lease. All other leases are classified as operating leases.

Rental income from operating leases is recognised on a straight-line basis over the term of the relevant lease. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised on a straight-line basis over the lease term.

Notes to the Consolidated Financial Statements
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Amounts due from lessees under finance leases are recognised as receivables at the amount of the Group's net investment in the leases. Finance lease income is allocated to accounting periods so as to reflect a constant periodic rate of return on the Group's net investment outstanding in respect of the leases.

When a contract includes lease and non-lease components, the Group applies AASB 15 to allocate consideration under the contract to each component.

[Leases under AASB 17, applicable before 1 January 2020]

Leases are classified as finance leases whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. All other leases are classified as operating leases.

The Group as lessor
Amounts due from lessees under finance leases are recognised as receivables at the amount of the Group's net investment in the leases. Finance lease income is allocated to accounting periods so as to reflect a constant periodic rate of return on the Group's net investment outstanding in respect of the leases.

Rental income from operating leases is recognised on a straight-line basis over the term of the relevant lease. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised on a straight-line basis over the lease term.

The Group as lessee
Assets held under finance leases are initially recognised as assets of the Group at their fair value at the inception of the lease or, if lower, at the present value of the minimum lease payments. The corresponding liability to the lessor is included in the statement of financial position as a finance lease obligation.

Lease payments are apportioned between finance expenses and reduction of the lease obligation so as to achieve a constant rate of interest on the remaining balance of the liability. Finance expenses are recognised immediately in profit or loss, unless they are directly attributable to qualifying assets, in which case they are capitalised in accordance with the Group's general policy on borrowing costs. Contingent rentals are recognised as expenses in the periods in which they are incurred.

Operating lease payments are recognised as an expense on a straight-line basis over the lease term, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed. Contingent rentals arising under operating leases are recognised as an expense in the period in which they are incurred. In the event that lease incentives are received to enter into operating leases, such incentives are recognised as a liability. The aggregate benefit of incentives is recognised as a reduction of rental expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

30m. 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.

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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.

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.

30n. 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.

30o. Trade and other payables
Trade and other payables are carried at amortised cost and due to their short-term nature, they are not discounted.

30p. Provisions
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.

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.

30q. 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.

Notes to the Consolidated Financial Statements
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30r. 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.

30s. 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.

30t. 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 derecognizes financial assets when the contractual rights to the cash flows expire or the financial asset is transferred to a 3rd 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.

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.

Notes to the Consolidated Financial Statements
Continued

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 (i.e., 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.

Notes to the Consolidated Financial Statements
Continued

ii Financial liabilities
Initial recognition and measurement
Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, financial liabilities at amortised cost, 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, and derivative financial instruments.

Subsequent measurement
For purposes of subsequent measurement, financial liabilities are classified in two categories:
- Financial liabilities at fair value through profit or loss
- Financial liabilities at amortised cost

Financial liabilities at fair value through profit or loss
Financial liabilities at fair value through profit or loss include 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. The Group has not designated any financial liability as at fair value through profit or loss.

Financial liabilities at amortised cost
This is the category most relevant to the Group. After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the 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. For more information, refer to Note 19.

Foreign exchange gains and losses
For financial liabilities that are denominated in a foreign currency and are measured at amortised cost at the end of each reporting period, the foreign exchange gains and losses are determined based on the amortised cost of the instruments. These foreign exchange gains and losses are recognised in the 'foreign exchange gain / (loss)' line item in profit or loss for financial liabilities that are not part of a designated hedging relationship. For those which are designated as a hedging instrument for a hedge of foreign currency risk foreign exchange gains and losses are recognised in other comprehensive income and accumulated in a separate component of equity.

The fair value of financial liabilities denominated in a foreign currency is determined in that foreign currency and translated at the spot rate at the end of the reporting period. For financial liabilities that are measured as at FVTPL, the foreign exchange component forms part of the fair value gains or losses and is recognised in profit or loss for financial liabilities that are not part of a designated hedging relationship.

Derecognition of financial liabilities
The Group derecognises financial liabilities when, and only when, the Group's obligations are discharged, cancelled or have expired. The difference between the carrying amount of the financial liability derecognised and the consideration paid and payable is recognised in profit or loss.

When the Group exchanges with the existing lender one debt instrument into another one with the substantially different terms, such exchange is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability. Similarly, the Group accounts for substantial modification of terms of an existing liability or part of it as an extinguishment of the original financial liability and the recognition of a new liability. It is assumed that the terms are substantially different if the discounted present value of the cash flows under the new terms, including any fees paid net of any fees received and discounted using the original effective rate is at least 10 per cent different from the discounted present value of the remaining cash flows of the original financial liability. If the modification is not substantial, the difference between: (1) the carrying amount of the liability before the modification; and (2) the present value of the cash flows after modification is recognised in profit or loss as the modification gain or loss within other gains and losses.

Notes to the Consolidated Financial Statements

Continued

iii. Fair value measurement

The Group measures derivatives at fair value at each balance sheet date and, for the purposes of impairment testing, uses fair value less costs to sell (FVLCD) to determine the recoverable amount of some of its non-financial assets.
Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:

- In the principal market for the asset or liability

Or

- In the absence of a principal market, in the most advantageous market for the asset or liability

The principal or the most advantageous market must be accessible by the Group.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs.

All assets and liabilities, for which fair value is measured or disclosed in the financial statements, are categorised within the fair value hierarchy, described as follows, based on the lowest-level input that is significant to the fair value measurement as a whole:
Level 1 – Quoted (unadjusted) market prices in active markets for identical assets or liabilities
Level 2 – Valuation techniques for which the lowest-level input that is significant to the fair value measurement is directly or indirectly observable
Level 3 – Valuation techniques for which the lowest-level input that is significant to the fair value measurement is unobservable

iv. 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.

Notes to the Consolidated Financial Statements
Continued

30u. 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.

30v 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.

Notes to the Consolidated Financial Statements
Continued

30w 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.

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 2020 are in accordance with the Corporations Act 2001, including:
   i. giving a true and fair view of its financial position as at 31 December 2020 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. 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 2020 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 2020.

29 April 2021
The Board of Directors
PetroNor E&P Ltd

Eyas Alhomouz
Chairman of the Board

Gro Kielland
Director of the Board

Joseph Iskander
Director of the Board

Roger Steinepreis
Director of the Board

Jens Pace
Director of the Board

Alexander Neuling
Director of the Board

Ingvil Smines Tybring-Gjedde
Director of the Board

Independent Auditors' 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 2020, 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 2020 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 (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

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.

Carrying value of Production assets and equipment

Key audit matter	How the matter was addressed in our audit
Refer to Note 15 of the financial statements, for disclosure over the Carrying value of Production assets and Equipment. The carrying value of Production assets and Equipment is impacted by various key estimates and judgements in particular: ● Reserves estimates; ● Amortisation rates; ● Capitalisation and attribution of production costs; and ● Life of production asset. The Group is also required to assess for indicators of impairment at each reporting period. The assessment of impairment indicators in relation to the Production assets and Equipment requires management to make significant accounting judgements and estimates which includes discount rates, commodity price and reserve estimates. This is a key audit matter due to the quantum of the asset and the significant judgement involved in management's assessment of the carrying value of Production assets and Equipment.	Our work with the assistance of our component auditors included, but was not limited, to the following procedures: ● Reviewing management's amortisation models, including agreeing key inputs tosupporting information; ● Assessing the competency and objectivity of, and work performed by, management's experts in respect of the reserve estimates; ● Assessing management's judgements over capitalisation of additions to production assets and equipment; – Evaluating and challenging management's assessment of indicators of impairment under the International Accounting Standards for the Production assets and Equipment by: – Comparing the carrying amount of the Group's net assets against the market capitalisation, both as at 31 December 2020, and subsequent movements; – Considering commodity price assumptions at 31 December 2020, including forecasts; – Comparing the carrying value to the independent reserves and valuation reports; – Reviewing board and sub-committee meeting minutes, and holding discussions with key management, including non-finance personnel; and – Assessing economic indicators for impacts on appropriate discount rates; and ● We also assessed the adequacy of related disclosures in Note 15 to the financial statements.

Independent Auditors' Report

Continued

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 2020, 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

BDO Audit (WA) Pty Ltd
Phillip Murdoch
Director
Perth
29 April 2021

Glossary of terms

Bbl	One barrel of oil, equal to 42 US gallons or 159 liters
Bcf	Billion cubic feet
bopd	Barrels of oil per day
boepd	Barrels of oil equivalent 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 Limited 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

Corporate Directory

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Joseph Iskander
Gro Kielland
Alexander Neuling
Jens Pace
Roger Steinepreis
Ingvil Smines Tybring-Gjedde

Company Secretary
Angeline Hicks

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