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29 March 2019

African Petroleum Corporation Limited
("African Petroleum" or the "Company")

Publication of Information Memorandum

Reference is made to the extended stock exchange announcement released on 19 March 2019 by African Petroleum (OSE ticker: "APCL") regarding the agreement to combine with PetroNor E&P Ltd for an all share consideration of c. 816 million shares in African Petroleum (the "Transaction").

In accordance with the Oslo Stock Exchange Continuing Obligations for listed companies section 3.5, African Petroleum has prepared an information memorandum (the "Information Memorandum") in relation to the contemplated Transaction. The Information Memorandum was approved by the Oslo Stock Exchange on 29 March 2019.

Completion of the Transaction is subject to certain conditions, including approval with requisite majority of the shareholders of the Company in a shareholders meeting to be held on 24 April 2019. Subject to fulfilment of applicable conditions, completion of the Transaction is targeted to occur by the end of April 2019. See the Information Memorandum for further information.

The Information Memorandum is attached hereto and is also available on the Company's website: www.africanpetroleum.com.au

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About African Petroleum

African Petroleum is an independent oil and gas exploration company with licence interests in offshore West Africa (Senegal and The Gambia). The Company's assets are located in proven hydrocarbon basins in the Atlantic Margin, where several discoveries have been made in recent years.

For more information about African Petroleum, please see www.africanpetroleum.com.au

IMPORTANT INFORMATION This release does not constitute an offer, invitation or solicitation of an offer to buy, subscribe or sell any shares in the Company. The distribution of this release in certain jurisdictions is restricted by law. This release is not for distribution or release, directly or indirectly, in or into any jurisdiction in which the distribution or release would be unlawful. Matters discussed in this release may contain certain forward-looking statements relating to the business, financial performance and results of the Company and/or the industry in which it operates, Forward-looking statements concern future circumstances and results and other statements that are not historical facts, sometimes identified by the words "believes", expects", "predicts", "intends", "projects", "plans", "estimates", "aims", "foresees", "anticipates", "targets", and similar expressions. Any forward-looking statements contained in this release, including assumptions, opinions and views of the Company or cited from third party sources are solely opinions and forecasts which are subject to risks, uncertainties and other factors that may cause actual events to differ materially from any anticipated development. Neither the Company nor any of its subsidiary undertakings or any such person's affiliates, officers or employees provides any assurance that the assumptions underlying such forward-looking statements are free from errors, nor do any of them accept any responsibility for the future accuracy of the opinions expressed in this release or the actual occurrence of the forecasted developments. The Company assumes no obligation to update any forward-looking statements or to confirm these forward-looking statements to our actual results.

INFORMATION MEMORANDUM

in connection with the acquisition of 100% of the shares in PetroNor E&P Ltd by

African Petroleum Corporation Limited

(A public limited liability company validly incorporated and registered in Australia under the Australian Corporations Act 2001)

The information in this information memorandum (the "Information Memorandum") relates to the contemplated acquisition of 100% of the shares in PetroNor E&P Ltd ("PetroNor", and together with its consolidated subsidiaries, the "PetroNor Group") by African Petroleum Corporation Limited (the "Company" or "African Petroleum", and, together with its consolidated subsidiaries, the "Group") (the "Transaction").

This Information Memorandum serves as an information document as required under Section 3.5 of the Continuing Obligations for Stock Exchange Listed Companies (the "Continuing Obligations"). It also serves as a prospectus equivalent document for the purpose of listing the new shares to be issued by the Company in connection with the Transaction, including new shares to be issued pursuant to exercise of the warrants described herein, cf. Section 7-5 no. 7 of the Norwegian Securities Trading Act of 29 June 2007. The Continuing Obligations apply in respect of companies with shares admitted to trading on Oslo Børs and Oslo Axess and this Information Memorandum has been submitted to Oslo Børs ASA (the "Oslo Stock Exchange") for inspection and review before it was published. This Information Memorandum is not a prospectus and has neither been inspected nor approved by the Oslo Stock Exchange or the Financial Supervisory Authority of Norway in accordance with the rules that apply to a prospectus. This Information Memorandum has been prepared in an English version only.

On 19 March 2019, the Company entered into a combination agreement with PetroNor and its shareholders NOR Energy AS ("NOR") and Petromal – Sole Proprietorship LLC ("Petromal") in respect of the Transaction. Subject to the terms and conditions of the Combination Agreement, the Company will acquire 100% of the shares in PetroNor, against consideration in the form of new shares in the Company (the "Consideration Shares") to be issued to NOR and Petromal. **All conditions for the Transaction have not been met at the date hereof and the Transaction has consequently not been completed. No assurance can be made that such conditions will be met or waived, or that the Transaction will be completed.**

This Information Memorandum does not constitute an offer to buy, subscribe or sell the securities described herein, and no securities are being offered or sold pursuant to this Information Memorandum.

In reviewing this Information Memorandum, you should carefully consider the matters described in Section 1 "Risk Factors" beginning on page 4.

Financial Advisor

Pareto Securities

The date of this Information Memorandum is 29 March 2019

IMPORTANT INFORMATION

This Information Memorandum has been prepared by the Company in connection with the Transaction.

For the definitions of terms used throughout this Information Memorandum, including the preceding page, see Section 12 "Definitions and glossary".

No shares or other securities are being offered or sold in any jurisdiction pursuant to this Information Memorandum.

All inquiries relating to this Information Memorandum must be directed to the Company. No other person is authorized to give any information about, or to make any representations on behalf of, the Company in connection with the Transaction. If any such information is given or representation made, it must not be relied upon as having been authorized by the Company. The information contained herein is as of the date hereof and is subject to change, completion and amendment without further notice. The publication of this Information Memorandum shall not under any circumstances create any implication that there has been no change in the Group's affairs or that the information set forth herein is correct as of any date subsequent to the date hereof.

The contents of this Information Memorandum are not to be construed as legal, business or tax advice. Each reader of this Information Memorandum should consult with its own legal, business or tax advisor as to legal, business or tax advice. If you are in any doubt about the contents of this Information Memorandum, you should consult your stockbroker, bank manager, lawyer, accountant or other professional advisor.

All conditions for the Transaction have not been met at the date hereof and the Transaction has consequently not been completed. No assurance can be made that such conditions will be met or waived, or that the Transaction will be completed.

The distribution of this Information Memorandum in certain jurisdictions may be restricted by law. The Company requires persons in possession of this Information Memorandum to inform themselves about, and to observe, any such restrictions. This Information Memorandum is not for publication or distribution, directly or indirectly, in the United States. The Company has not registered any of the shares issued by the Company (the "Shares") under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), and the Shares may not be offered or sold, directly or indirectly, in the United States absent registration except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act and in compliance with any applicable securities laws of any state or other jurisdiction of the United States. The Company does not intend to register any of the Shares pursuant to the U.S. Securities Act.

This Information Memorandum shall be governed by Norwegian law. Any dispute arising in respect of this Information Memorandum is subject to the exclusive jurisdiction of the Norwegian courts, with Oslo District Court as legal venue.

Investing in the Company's Shares involves risk. See Section 1 "Risk factors" below.

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APPENDICES

1 RISK FACTORS

The following risk factors and all other information contained in this Information Memorandum, including the financial statements and related notes, should be carefully considered when analysing the Company, the Group, the PetroNor Group and/or the Transaction. For the purpose of these risk factors, "Group" includes the PetroNor Group and its business, results of operations, cash flows, financial condition and/or prospects. The risks and uncertainties described in this Section 1 are the principal known risks and uncertainties faced by the Group as of the date hereof that the Company believes are the material risks relevant to the Group. The absence of negative past experience associated with a given risk factor does not mean that the risks and uncertainties described herein should not be considered when analysing the Company and the Group. If any of the following risks were to materialise, individually or together with other circumstances, they could have a material and adverse effect on the Group and/or its business, results of operations, cash flows, financial condition and/or prospects, which may cause a decline in the value and trading price of the Shares in the Company.

The order in which the risks are presented does not reflect the likelihood of their occurrence or the magnitude of their potential impact on the Group's business, results of operations, cash flows, financial condition and/or prospects. The risks mentioned herein could materialise individually or cumulatively. The information in this Section 1 is as of the date of this Information Memorandum.

1.1 Risks related to the countries in which the Group operates

1.1.1 The Group operates in developing countries facing political, economic and social uncertainties

The Group participates or expects to participate in oil and gas projects in countries in West Africa with emerging economies, including but not limited to Senegal and The Gambia, and following completion of the Transaction, Congo Brazzaville and potentially Nigeria. Oil and gas exploration, development and production activities in such emerging markets are subject to significant political and economic uncertainties that may have a material adverse effect on the Group. Uncertainties 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, and the imposition of currency controls.

Developing countries are subject to rapid change and the information set forth in this Information Memorandum may become outdated relatively quickly. Moreover, financial turmoil in developing countries tend to adversely affect prices in equity markets of other developing countries as investors move their money to more stable, developed markets. Thus, financial turmoil in any developing countries in which the Group operates could adversely affect the Group's business, financial condition, results of operations and prospects as well as result in a decrease in the price of the Shares.

There may also be uncertainties related to the imposition of international sanctions in the countries in which the Group operates. Travel bans, asset freezes or other sanctions may be imposed and have historically been imposed on countries in which the Group operates.

The uncertainties listed above, all of which are beyond the Group's control, could have a material adverse effect on the Group's business, prospects, financial position and/or results of operations.

1.1.2 The Group operates in countries with a high risk of corrupt practices

Certain jurisdictions in which the Group has operations have 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. The Group's core assets are located in Senegal, and The Gambia. In addition, following completion of the Transaction, the Group will have assets in Congo Brazzaville and target to acquire assets in Nigeria and other countries in Africa. The production sharing or other licencing contracts in such jurisdictions provide for payments to the Governments and/or national oil companies (farm-in fees, signature bonuses, taxes, training budgets, equipment budgets, carry of certain expenditures etc). Furthermore, the Group has a number of consultants working for it in the area. Although the Group believes all its consultancy agreements are entered into on clear and transparent terms, there is a risk that agents or other persons acting on behalf of the Group may engage in corrupt activities without the knowledge of the Group.

The Group has put in place internal regulations and contractual commitments to remain compliant with all applicable corruption compliance regulations. The Group maintains a zero tolerance policy towards bribery by any of its employees and agents. The Group is also subject to the provisions of, *inter alia,* the UK Bribery Act, and external audits and controls carried out by representatives of its contracting parties to this effect. However, corrupt practices of third parties or anyone working for the Group, 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.

1.1.3 Risk relating to local partners and government affiliations

The operations of the Group are located in parts of the world where there is an inherent risk of corruption. For the Group's assets in the oil and gas segment in Congo Brazzaville this risk is regarded as substantial. According to Transparency International, Congo Brazzaville ranks 19 on a scale from 0 (highly corrupt) to 100 (very clean) measuring public sector corruption. The Group has extensive experience in carrying out business operations under such challenging conditions. Moreover, the Group has implemented measures to mitigate such exposure.

Under Congolese law local participation is required in the oil and gas sector, but it may prove difficult to always receive final confirmation as to who the ultimate owners and affiliations of such local partners are. Through the Group's investigation, it has not been possible to substantiate ultimate ownership and affiliations of all, current local partners in Congo and there can be no assurance that there are no government affiliations within the ultimate shareholders of the local partners in Congo.

As mentioned in Section 1.1.2 "The Group operates in countries with a high risk of corrupt practices" above, the Group has put in place internal regulations and contractual commitments to remain compliant with all applicable corruption compliance regulations. Despite such policies and procedures being in place there can be no assurance that the Group can be exposed for situations involving breach or alleged breach of applicable anti-corruption laws. The Group maintains a zero tolerance policy towards bribery by any of its employees and agents. The Group is also subject to the provisions of, *inter alia*, the UK Bribery Act, and external audits and controls carried out by representatives of its contracting parties to this effect. However, corrupt practices of third parties or anyone working for the Group, 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.

1.1.4 The Group operates in areas where there is a risk of war, social and civil unrest, armed conflicts, piracy and/or terrorist attacks

The Group operates in certain countries with recent history of political instability, and strong political tension, turmoil and factional fighting. Although the political situation in the countries in which the Group operates currently is relatively stable, there can be no assurance that the Group and its operations will not be materially negatively impacted by instability in the future.

War, social and civil unrest, conflicts, military tension and/or terrorist attacks may cause instability in the areas in which the Group is operating, or may cause instability in the world's financial and commercial markets. Political and economic instability may occur in some of the geographic areas in which the Group operates (or may operate in the future) and may contribute to disruptions of operations, loss or seizure of vessels, kidnapping of marine crew or onshore employees, piracy and other adverse effects including increased operating costs.

In addition, acts of terrorism and threats of armed conflicts in or around various areas in which the Group operates (or may operate in the future) could limit or disrupt the Group's operations, including disruptions from evacuation of personnel, cancellation of contracts or the loss or injury of personnel or loss or damage to its assets.

Armed conflicts, terrorism and their effects on the Group or its markets may have a significant adverse effect on the Group's business, financial condition, cash flow, prospects and/or results of operations in the future.

1.1.5 The Group operates in areas with different legal systems and litigation

The Group's activities are located in countries with legal systems that in various degrees differ from those of Australia, the UK and Norway. Rules, regulations and legal principles may differ both relating to matters of substantive law and in respect of matters such as court procedure and enforcement. Almost all material production and exploration rights and related contracts of the Group are subject to the national or local laws and jurisdiction of the respective countries in which the licences are held. This means that the Group's legal protection and ability to exercise or enforce its rights and obligations may differ between different countries and also from what would have been the case if such rights and obligations were subject to Australian, UK or Norwegian law and jurisdiction. The Group's operations are, to a large extent, subject to several complex laws and regulations as well as detailed provisions in concessions, licences and agreements that often involve several parties. If the Group fails to obtain legal protection of its rights or to enforce its rights under the different applicable legal systems, this could have a material adverse effect on the Group, its financial condition, cash flow, prospects and/or operations.

1.2 Risks related to the business of the Group

1.2.1 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 declines in recent years. Oil and gas prices are unstable and are subject to significant fluctuations for many reasons including, but not limited to:

- changes in global and regional supply and demand, and expectations regarding future supply and demand for oil and gas, even relatively minor changes;
- geopolitical uncertainty;
- availability of pipelines, tankers and other transportation and processing facilities;
- proximity to, and the capacity and cost of, transportation;
- petroleum refining capacity;
- price, availability and government subsidies of alternative fuels;
- price and availability of new technologies;
- the ability and willingness of the members of the Organization of Petroleum Exporting Countries ("OPEC") and other oil-producing nations to set and maintain specified levels of production and prices;
- political, economic and military developments in producing regions, particularly the Middle East, Russia, Africa and Central and South America, and domestic and foreign governmental regulations and actions, including import and export restrictions, taxes, repatriations and nationalisations;
- global and regional economic conditions;

- trading activities by market participations and others either seeking to secure access to oil and gas or to hedge against commercial risks, or as part of investment portfolio activity;
- weather conditions and natural disasters; and
- terrorism or the threat of terrorism, war or threat of war, which may affect supply, transportation or demand for hydrocarbons and refined petroleum products.

Sustained lower oil and gas prices or price declines may *inter alia* lead to a material decrease in the Group's net production revenues.

The Group may from time to time enter into hedging arrangements in the form of put options to offset the risk of revenue losses if commodity prices decline. However, such arrangements may be expensive and there can be no assurance that hedging will be available or continue to be available on commercially reasonable terms. In addition, hedging itself carries certain risks, including expenses associated with terminating any hedging agreements.

Further, sustained lower oil and gas prices may also cause the Group to make substantial downward adjustments to its oil and gas reserves. If this occurs, or if the Group's estimates of production or economic factors change, the Group may be required to write-down the carrying value of its proved oil and gas properties for impairments. In addition, the depreciation of oil and gas assets charged to its income statement is dependent on the estimate of its oil and gas reserves. Further, certain development projects which are or become of substantial importance to the Group could become unprofitable as a result of a decline in price and could result in the Group having to postpone or cancel a planned project, or if it is not possible to cancel the project, carry out the project with negative economic impact. Additionally, if oil and gas prices remain depressed over time, it could reduce the Group's ability to raise new debt or equity financing or to refinance any outstanding loans on terms satisfactory, or at all.

1.2.2 Reserves and contingent resources are by their nature uncertain in respect of the inferred volume range

Included in this Information Memorandum is information relating to the reserves and resources of certain of the Group's assets and certain assets comprised by the Transaction. Reserves are defined as the volume of hydrocarbons that are expected to be produced from known accumulations in production, under development or with development committed. Reserves are also classified according to the associated risks and probability that the reserves will be actually produced. 1P – Proven reserves represent volumes that will be recovered with 90% probability, 2P – Proven + Probable represent volumes that will be recovered with 50% probability and 3P – Proven + Probable + Possible represent 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 or where development is unlikely with present basic assumptions (e.g. due to the lack of a firm plan of development with the necessary partner or governmental approval, the lack of a market, or the lack of the proper delineation necessary to establish the size of the accumulation for commercial purposes), or under evaluation. Contingent resources are reported as 1C, 2C, and 3C, reflecting similar probabilities as reserves.

Many of the factors in respect of which assumptions are made when estimating reserves and resources are beyond the Group's control and therefore these assumptions may prove to be incorrect over time. For example, sustained lower oil and gas prices may cause the Group to make substantial downward adjustments to its oil and gas reserves and resources. If this occurs, or the Group's estimates of production or economic factors change, the Group may be required to write-down the carrying value of its proved oil and gas properties for impairments. In addition, the depreciation of oil and gas assets charged to its income statement is dependent on the estimate of its oil and gas reserves.

Evaluations of reserves and resources necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and petroleum engineering and geological interpretation. Exploration drilling, interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in the Group's reserves or resources data.

Moreover, different reservoir engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material. Also, effects of regulations adopted by governmental agencies, future operating costs, royalties, tax on the extraction of commercial minerals, development costs and well work-over and remedial costs represent further variables and assumptions which makes the estimation of reserves and resources uncertain and potentially incorrect.

Special uncertainties exist with respect to the estimation of resources in addition to those set forth above that apply to reserves, such as:

- the quantities and qualities that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of additional exploration and future development expenditures;
- demand for oil and gas; and
- future oil and gas sales prices.

The probability that contingent resources will be economically developed, or be economically recoverable, is considerably lower than for proven, probable and possible reserves. Forward-looking statements contained in this Information Memorandum concerning the reserves and resources definitions should not be unduly relied upon by potential investors. If the assumptions upon which the estimates of the Group's oil and gas reserves or resources are based prove to be incorrect, the Group may be unable to recover and/or produce the estimated levels or quality of oil or gas set out in this Information Memorandum, which could have a material adverse effect on the Group's business, prospects, financial condition or results of operations.

Completion of a well does not guarantee a profit on the investment or recovery of the costs associated with that well. Additionally, the cost of operations and production from successful wells may be materially adversely affected by unusual or unexpected geological formation pressures, oceanographic conditions, hazardous weather conditions, delays in obtaining governmental approvals or consents, shut-ins of connected wells, difficulties arising from environmental or other challenges or other factors. Any inability on the Group's part to recover its costs and generate profits from its exploration and production activities could have a material adverse effect on its business, results of operations, cash flow and financial condition.

1.2.3 The Group is dependent on finding/acquiring, developing and producing oil and gas reserves that are economically recoverable and offshore exploration is by its nature highly speculative

The future success of the Group depends in part on its ability to find and develop or acquire additional reserves that are economically recoverable, which is dependent on oil and gas prices. Oil and gas exploration and production activities are capital intensive and inherently uncertain in their outcome. The Group's offshore acreage is located in largely unexplored sections of the West African deep water margin. The Group has drilled three wells in offshore Liberia and one well in offshore Côte d'Ivoire; however, the Company did not announce a discovery that is estimated to be possible to develop commercially and the licences held by the Company in Liberia and Côte d'Ivoire were subsequently relinquished.

Some of the Group's projects are in an early exploration stage, and there is a risk that any future exploration programs on these and any licences the Group may acquire in the future (whether offshore or onshore) may be unsuccessful and may not discover commercial quantities of hydrocarbons.

Ultimate and continuous success of these activities is dependent on many factors such as:

- the discovery and/or acquisition of economical reserves;
- access to adequate capital for project development;
- design and construction of efficient development and production infrastructure within capital expenditure budgets;
- securing and maintaining title to interests;
- obtaining consents and approvals necessary for the conduct of oil and gas exploration, development and production; and
- access to competent operational management and prudent financial administration, including the availability and reliability of appropriately skilled and experienced employees, contractors and consultants.

Drilling oil and gas wells (whether offshore or onshore) is by its nature highly speculative, may be unprofitable and may result in a total loss of the investments made by the Group. In particular, completed wells may never produce oil or gas or may not produce sufficient quantities or qualities of oil and gas to be profitable or commercially viable. Moreover, geological formations and proximity with neighbouring fields may result in a regulatory requirement to unitize the license area with a neighbouring field. Such processes may prove complex, and thereby cause delays and uncertainties in respect of the Group's ultimate interest in the unitized field.

Few prospects that are explored are ultimately developed into producing oil and gas fields. Whether or not income will result from projects undergoing exploration and development programs depends on successful exploration and establishment of production facilities. Factors including costs, actual hydrocarbons and formations, flow consistency and reliability and commodity prices affect successful project development and operations.

There is no assurance that any exploration of current or future interests will result in the discovery of an economic deposit of oil or gas. Even if an apparently viable deposit is identified, there is no guarantee that it can be economically developed. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs, as there is no guarantee that the wells that are productive will produce sufficient net revenues to cover any such costs.

In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In the event of a commercial discovery, the development of hydrocarbon reserves, particularly in the offshore arena where the Group primarily operates, depends on a number of factors such as the type and size of the reservoir, the proximity to existing infrastructure with adequate capacity for new production, and available markets for any production. In addition, the Group is exposed to risks such as weather and other factors that can often result in delays and unanticipated cost overruns.

All of these risks may have a material adverse effect on the Group, its financial condition, cash flow, prospects and/or operations.

1.2.4 The Group's operations are capital intensive and involve a high degree of risk

Oil and gas exploration and production activities are capital intensive and involve a high degree of risk. The Group is required to make substantial capital expenditure for the acquisition, exploration, development and production of oil and gas reserves in the future. See Section 1.4 "Financial risks" for a description of the financial risks of the Group. Such capital expenditures could be covered by future revenues, divestment of assets/farm-outs, carry arrangements, new equity or by obtaining new debt financing. If the Group in the future fails to generate sufficient revenue, or if the Group is unable to attract investors to increase the Group's equity, or if sufficient new debt arrangements, asset divestment arrangements/ farm-outs and/or capital expenditure financings are not accessible, or only accessible on unattractive commercial terms, the Group will have a limited ability to undertake or complete future exploration programs, maintenance of existing assets, development investments and acquisitions.

Limited available capital will also impact the Group's ability to maintain existing assets and undertake exploration and development initiatives. The Group's inability to access sufficient capital for its operations could lead to licences being revoked or relinquished or default by the Group under commercial arrangements, including joint venture agreements, or otherwise have a material adverse effect on the Group's financial conditions, results of operations, cash flow and/or prospects in general.

There is no assurance that expenditures made on future exploration by the Group will result in new discoveries of oil or gas in commercial quantities. It is difficult to estimate the costs of implementing any exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over-pressured zones, tools lost in the well bore and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. If exploration activities prove unsuccessful over a prolonged period of time, the Group' may not have sufficient working capital to continue to meet its obligations and its ability to obtain additional financing necessary to continue operations may also be adversely affected.

All of these risks may have a material adverse effect on the Group, its financial condition, cash flow, prospects and/or its operations.

1.2.5 Availability of drilling equipment, coordination of exploration and production activities and access restrictions

All of the Group's licences are offshore exploration projects. These projects require the co-ordination of a number of activities including obtaining seismic and electromagnetic data, carrying out subsea surveys, and where relevant; obtaining partner approvals and securing rig capacity for the necessary drilling activities. Although the Company currently considers the deep-water rig availability to be generally favourable for the Company and the Group, no assurance can be given that the Group will be able to secure drilling rig capacity to perform its well commitments by the relevant due dates. If the Group fails to successfully co-ordinate the timely delivery or completion of these activities, it may miss out on exploration opportunities and/or it may be required to make additional expenditure.

Furthermore, contracting drilling rigs requires significant financial commitment and investment and rates and costs for rigs and other equipment can fluctuate considerably Furthermore, as set out in section 2.5.3, the Company is dependent on a farm-out of one or more of its licences and/or on raising additional equity in order to be able to meet minimum investment work program requirements in the current exploration periods in certain of its licences. If such requirements are not met, the Group would be at risk of having the affected licences terminated.

Furthermore, the Group is dependent on available and functioning infrastructure and support functions relating to the properties on which it operates such as, supply bases, support vessels and other logistical services. If any infrastructure or system failures occur or do not meet the requirements of the Group, the Group's operations may be significantly hampered which could result in delayed, postponed or cancelled petroleum operations and/or higher costs. This could have a material adverse effect on the Group's financial condition, results of operations and/or cash flows. In most of the areas in which the Group operates, very little infrastructure and support functions of any sort that are commonly associated with petroleum operations are in existence.

1.2.6 Approvals, permits and licences

Under applicable laws and regulations in certain of the countries where the Group operates, the Group will be required to renew its licences with respect to exploration activities. In addition, the Group would be required, subject to commercial petroleum discoveries being made, to apply for exclusive exploitation authorisations.

If any of these exploration and production licences are not renewed or granted or exclusive exploitation authorisations are not obtained, the Group would be required to cease operations of the affected well or production facility. The loss of some or all of the Group's licences may have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

Further, the Group's license interests for the exploration and exploitation of hydrocarbons will typically be subject to certain financial obligations or work commitments as imposed by local authorities. The existence and content of such obligations and commitments may affect the economic and commercial attractiveness for such license interest. No assurance can be given that local authorities do not unilaterally amend current and known obligations and commitments. If such amendments are made in the future, the value and commercial and economic viability of such interest could be materially reduced or even lost, in which case the Group's financial position and future prospects could also be materially weakened.

1.2.7 Risks associated with legal disputes, different legal systems and litigation

The Group is, and may from time to time be, involved in legal disputes and legal proceedings related to the Group's operations or otherwise. To the extent the Group becomes involved in legal disputes in order to defend or enforce any of its rights or obligations under its licences, agreements or otherwise, such disputes or related litigation may be costly, time consuming and the outcome may be highly uncertain. Furthermore, legal proceedings could be ruled against the Group and the Group could be required to, *inter alia*, pay damages, halt its operations, stop its expansion projects, etc. It is further a risk that the Group could become involved in legal disputes with uninsured third parties. Even if the Group would ultimately prevail (which cannot be assured), such disputes and litigation may have a substantially negative effect on the Group, its financial condition, cash flow, prospects and/or its operations.

The occurrence of any such event could have a material adverse effect on the Group's business, prospects, financial position and/or results of operations.

As at the date of this Information Memorandum, the Group is involved, *inter alia*, in the following disputes (see Section 5.7 "Legal and arbitrational proceedings" and Section 8.5 "Litigation, disputes and tax" for all disputes): As the claimant in The International Centre for the Settlement of Investment Disputes ("ICSID") arbitration case

ARB/17/38 in relation to its 100% interest in the A1 and A4 licences in The Gambia and as the claimant in ICSID arbitration ARB/18/24 in relation to its 90% interest in the Rusfique Offshore Profond block ("ROP") and the Offshore Sud Profond block ("SOSP") licences in Senegal. The Group is dependent on a successful outcome in the arbitration cases in order to have its respective licences re-instated. The Group has no control over the outcome of the arbitration cases. Should the outcome of the arbitration cases be unfavourable to the Group, this will have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.2.8 Risk of joint and several liabilities with its licence partners

Under each licence, the Group is liable on a joint and several basis together with its licence partners for the liabilities of the licence group (including but not limited to decommissioning liabilities). Whilst such joint and several liability is regulated among the licence group through the joint operating agreement, ultimately failure by a licence partner to satisfy its obligations may result in the other licence partners (including the Group) being liable for such failure and therefore increase the Group's exposure related to the licence in question. As a consequence of joint and several liabilities, any failure by a licence partner to satisfy any significant obligations may have a material adverse effect on the Group's business, financial condition, operating results and/or cash flow.

1.2.9 The Group is dependent on senior executives, key personnel and local content

The Group's development and prospects depend on the continued services and performance of its senior management and other key personnel. The loss of the services of any of the senior management or key personnel may have a material adverse impact on the Group. Due to the risks of the areas where the Group operates, key personnel may sometimes only be obtained or retained at a high cost to the Group.

The loss of any member of senior management may result in a loss of organizational focus, poor operating execution or an inability to identify and execute potential strategic initiatives such as international expansion. The Group is subject to laws and regulations regarding local content for its operations in West Africa. The availability of skilled local manpower may be limited and may restrict the Group's ability to retain the necessary local capability, increase the cost of personnel or cause the Group to be unable to win contracts which are dependent on high levels of local content.

The inability of the Group to recruit and/or retain key personnel and/or local content could have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.2.10 Health, safety and environmental risks

All phases of the oil business present environmental risks and hazards and are subject to environmental regulation pursuant to numerous international conventions and EU and state and municipal laws and regulations, concerning health, safety and environmental ("HSE") matters including, but not limited to, those relating to the health and safety of employees, discharges of hazardous substances into the environment and the handling and disposal of waste. The technical requirements of these laws and regulations are becoming increasingly complex, stringently enforced and expensive to comply with and this trend is likely to continue. The failure to comply with applicable HSE laws and regulations may result in regulatory action, the imposition of fines or the payment of compensation to third parties which each in turn could have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

The Group's exploration activities and potential operations in the countries where the Group operates are regulated by laws with respect to environmental issues (such as water quality, air quality, dust impact, water bed, and fauna impact) and planning issues (such as approval to lay a pipeline). Some of these countries' governments require petroleum companies to post cash deposits or give other security on the area which is being used for exploration and production, with those cash deposits being returned or security released after satisfactory reclamation is completed.

Many of the activities and operations of the Group are environmentally sensitive and cannot be carried out without prior approval from all relevant authorities. The Group intends to conduct its activities in an environmentally responsible manner and in accordance with all applicable laws. However, the Group may be liable for environmental rehabilitation, damage control and losses due to risks inherent in its activities, such as accidental spills, leakages or other unforeseen circumstances. If environmental laws are breached these could result in substantial fines and/or closure of the Group's operations.

The licences entered into by the Group with governments contain obligations on the Group to provide effective and safe system for disposal of water and waste oil, oil base mud and cuttings, to control the flow and prevent the escape of avoidable waste, to prevent damage to onshore lands and to trees, crops, buildings or other structures, to prevent damage to marine life and fishing activities.

There is also a risk that the environmental laws and regulations may become even more onerous, increasing the Group's operating costs.

Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of substantial fines and penalties. Environmental legislation, moreover, is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to material liabilities and foreign governments or third parties may require the Group to incur costs to remedy such discharges. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.2.11 Operating risks

The operations of the Group may be materially affected by various factors, including failure to locate or identify hydrocarbon reserves, failure to achieve predicted well production flow rates, operational and technical difficulties encountered in exploration or production, difficulties in commissioning and operating plant and equipment, mechanical failure or plant breakdown, unanticipated reservoir problems which may affect field production performance, adverse weather conditions, industrial and environmental accidents, industrial disputes and unexpected shortages or increases in the costs of consumables, spare parts, plant and equipment. All of such factors may have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.2.12 Potential acquisitions

The Group may in the future make acquisitions of, or significant investments in, complementary companies or prospects and additional licences. The Group will complete appropriate due diligence prior to making an investment. Such due diligence will primarily be based on information which may only be available through certain third parties. Such information may be erroneous, incomplete and/or misleading, and there can be no assurance that all material issues will be uncovered. Moreover, the Group may only participate in a limited number of investments so that returns might be adversely affected by the poor performance of even a single investment. There is always a possibility that intended transactions might not conclude due to various execution risks related to, but not limited to, documentation, regulatory approvals and/or due diligence. Thus there might be certain external and third party costs carried by the Group that are not recoverable. The materialisation of any of the aforementioned risks may have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.2.13 Third party contractors

The Group is highly dependent on third party contractors and is, *inter alia* unable to predict the risk of:

- financial failure or default by a participant in any joint venture to which the Group may become a party; or
- insolvency or other managerial failure by any of the operators and contractors used by the Group; and/or
- insolvency or other managerial failure by any of the other service providers used by the Group for any activity.

1.2.14 Insurance

Oil and natural gas exploration, development, and production operations are subject to associated risks and hazards, such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property, and the environment or personal injury. Insurance against all risks associated with oil and gas production is not available or affordable. The Group will maintain insurance where it is considered appropriate for its needs, however, it will not be insured against all risks either because appropriate cover is not available or because the Group considers the required premiums to be excessive having regard to the assumed benefits that would accrue. The Group may incur material uninsured losses or damages that may have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.3 Risks related to the industry

1.3.1 The industry in which the Group operates is highly competitive

The oil and gas industry is highly competitive in all its phases. There is strong competition for the discovery and acquisition of properties considered to have commercial potential. The Group competes with other exploration and production companies, many of which include major international oil and gas companies which may have greater financial resources, staff and facilities than those of the Group. These companies have strong market power as a result of several factors, such as the diversification and reduction of risk, including geological, price and currency risks; better financial strength facilitating major capital expenditures; greater integration and the exploitation of economies of scale in technology and organization; stronger technical experience; better infrastructure and reserves; and stronger brand recognition. Due to this competitive environment, the Group may be unable to acquire attractive suitable properties or prospects on terms that it considers acceptable. As a result, the Group's revenues may decline over time, thereby materially and adversely affecting its financial condition, business, cash flow, prospects and/or results.

1.3.2 Regulation of the oil industry

The Group's operations in the countries in which it operates, are or will be subject to laws and regulations of general application governing exploration production and processing of hydrocarbons, land tenure and use, environmental matters, including but not limited to site-specific environmental licences, permits and statutory authorisations, and laws and regulations regarding industry relations, work place health and safety, trade and export, competition, access to infrastructure and taxation. These regulations are implemented by various governments and authorities and could be costly or difficult to comply with and could hence have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.3.3 Production sharing contracts (PSCs)

PSCs are common contracts signed between a government and a resource extraction company. The Group has entered into certain PSCs with local governments. Accordingly, the production resulting from oil operations must be shared between the Group and such government. The local governments also have an option to increase its participation in the relevant licences.

The sharing of the production will naturally affect the profitability of the Group and/or the amount of profits from the project that will flow to the Company and its shareholders. This could be affected further if the government decides to increase its participation or the size of its share.

1.3.4 Commercialisation risks

Even if the Group discovers commercial quantities of oil, there is a risk that the Group will not achieve a commercial return. The Group may not be able to produce and/or transport the oil at a reasonable cost or may not be able to sell the oil to customers at a rate which would cover its operating and capital costs. The Group has to receive regulatory and environmental approval to convert its exploration permits into production concessions. There is a risk that these approvals may not be obtained.

All of these risks may have a material adverse effect on the Group, its financial condition, cash flow, prospects and/or operations.

1.4 Financial risks

1.4.1 Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they fall due. The Group's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to its reputation.

The Group manages liquidity risk by maintaining adequate cash reserves from funds raised in the market and by continuously monitoring forecast and actual cash flows.

Notwithstanding the Group's efforts to manage the liquidity risk, there can be no assurance that the Group will have, or be able to secure, sufficient funding to meet its financial obligations as they fall due and such failure could have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results and may entail that the Group would not be able to continue as a going concern. In the event that the Group is not able to continue as a going concern, there can be no assurance that the Group will be able to realise its assets and extinguish its liabilities in the normal course of business and at the amounts stated in this financial report.

1.4.2 Future funding requirement and risk of not meeting work commitments

Assuming a successful outcome of the arbitration proceedings in relation to the Group's interests in the A1 and A4 licences in The Gambia and/or the ROP and SOSP PSCs in Senegal, the Group will be dependent on further funding transactions and/or farm-out transactions in order to fund its operations from the second half of 2020 onwards. Based on the Group's current cash balances, the Group is in a position to finance its operations and its arbitration proceedings in 2019 and 2020; however, the Group will need to complete one or more farm-out transactions or other significant funding in order to finance operations and planned investments from the second half of 2020 onwards, assuming a successful outcome in the arbitration proceedings.

Should the Group's exploration licences be re-instated it is expected that they will include minimum investment work programs which must be met in order for the Group to maintain the licences. For certain of the Group's licences, it is expected that the minimum investment work programs will require material investments during a relatively short period of time (seven to twelve years), including drilling of exploration wells in 2021 and 2022.

Based on the Group's current cash balances and budgeted spending in 2019 and 2020, the Group will be in a position to finance its participation in the arbitration proceedings; however, should the Licences be re-instated it will not be in a position to finance its participation in a material portion of the expected minimum investment requirements under the Licences for 2021 without completing one or more farm-out transactions or other significant funding during 2021.

There can be no assurance that the Group will have its Licences re-instated, or complete farm-outs, or that the Group will be able to meet minimum investment work program requirements. The non-occurrence of any such event may have a material adverse effect on the Group's business, results of operation, prospects and liquidity.

See also Section 1.4.3 "Dependency on farm-outs" below for further details on the Group's dependency on farm-outs and Section 5 "Presentation of African Petroleum" for further information regarding the arbitration proceedings and licence terms.

1.4.3 Dependency on farm-outs

The Group seeks to fund a material portion of its operations through farm-outs of parts of its licence interests to industry partners. A key merit of the farm-out strategy is to introduce additional technical competence from industry partners in the evaluation and development of the Group's licence interests. In addition, the Group targets to reduce its cost of operations to preserve its cash balances and diversify its exploration risk. The Group is depending on farm-outs of one or more of its licences and/or raising additional equity, in order to be able to meet the expected outstanding work commitments in certain of its licences should they be re-instated. There can be no assurance that the Company will be able to obtain farm-outs in time or at all to meet the minimum work commitments on its Licences and this may in turn have a material adverse effect on the Group, its financial condition, cash flow, prospects and/or operations.

1.4.4 Additional requirements for capital

The Group's capital requirements depend on numerous factors. Depending, inter alia on the Group's level of production of hydrocarbons, capital investments and requirements, arbitration success and completion of farm-out transactions, the Group may require further financing in the future. Any additional equity financing will dilute shareholdings, and debt financing, if available, may involve restrictions on financing and operating activities. If the Group is unable to obtain additional financing as needed at all or on acceptable terms, it may be required to reduce the scope of its operations and scale back its exploration programs as the case may be, which again could have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results. The Combined Group will have a credit facility with initial amount of USD 15 million with Forfaiting Trading (Bermuda) Limited. PetroNor is currently in dialogue to renegotiate the Forfaiting Trading loan with the administrative agent, Rasmala Trade Finance Fund. There can be no assurance that the renegotiation of the loan will be successful on terms acceptable to the Combined Group, or at all.

1.4.5 Interest rate risk

The Group may be exposed to interest rate risk, which is the risk that a financial instrument's value will fluctuate as a result of changes in the market interest rates on interest bearing financial instruments. Unless such exposure is mitigated, the Group could realise material losses in the future. Currently, the Group has no arrangements in place to mitigate such exposure, and there can be no assurance that the Group will be able to establish such arrangements in the future.

1.4.6 Foreign currency risk

The Group is exposed to currency risk on contracts that are denominated in a currency other than the respective functional currencies of the entities making up the Group, which is primarily the United States Dollar (USD). The Group has not entered into any derivative financial instrument to hedge such risks and may as a result incur material losses.

As a result of the Company's functional currency being in Australian Dollars (AUD) and several subsidiaries' functional currency being USD, the Group's financial statements and financial condition can be significantly adversely affected by movements in the USD/AUD exchange rates.

1.4.7 Credit risk

Credit risk arises from the financial assets of the Group, which comprise cash and cash equivalents, trade and other receivables and available-for-sale financial assets. The Group's exposure to credit risk arises from potential default of the counterparty, with a maximum exposure equal to the carrying amount of the financial assets (as outlined in each applicable note).

The Company has adopted the policy of only dealing with creditworthy counterparties and obtaining sufficient collateral or other security where appropriate, as a means of mitigating the risk of financial loss from defaults. The Company does not have any significant credit risk exposure to any single counterparty.

- <u>Cash and cash equivalents</u> - The Company limits its exposure to credit risk by only investing in liquid securities and only with counterparties that have an acceptable credit rating.

- <u>Trade and other receivables -</u> Trade and other receivables as at the reporting date mainly comprise goods and services tax ("GST") and short term loans to be refunded to the Company. The Directors consider that the carrying amount of trade and other receivables approximates their fair value.

The Company has established an allowance for impairment that represents its estimate of incurred losses in respect of other receivables and investments. Management does not expect any counterparty to fail to meet their obligations.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit ratings (if available) or to historical information about counterparty default rates.

Notwithstanding the Group's efforts to manage the credit risk, there can be no assurance that the Group will not incur significant losses due to its counterparties' inability or unwillingness to honour its obligations that could have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.4.8 Risk of change in legislation and tax laws

The Company has no control of potential future changes to applicable legislation and tax laws under which the Group operates. Future changes to such legislation and tax laws may have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

1.5 Risks related to the Transaction

1.5.1 The Group's future results may materially differ from the results portrayed in the unaudited pro forma financial information

This Information Memorandum includes unaudited pro forma consolidated financial information for the Group as of and for the year ending 31 December 2017. The unaudited pro forma financial information have been prepared solely for illustrative purposes and to show what the significant effects of the Transaction might have been had the Transaction occurred at an earlier date. The unaudited pro forma financial information is based on preliminary assumptions and estimates believed to be reasonable in light of the current circumstances. Actual results could however have materially differed from the results presented in the unaudited pro forma financial information and the presented results are therefore not necessarily indicative of the Group's future results.

1.5.2 The Company may not be able to successfully combine the business of the Company and PetroNor

Following the Transaction, PetroNor will be an integrated part of the Group. A combination of two previously independently operated groups, involves risk. There can be no assurance that the Group will meet the challenges involved with an integration or that the anticipated benefits from the Transaction will be achieved. Failure to achieve the expected advantages or any delays, unexpected difficulties or unanticipated costs incurred in the combination process, may have a material adverse effect on the Group's operating results and overall financial condition.

1.5.3 The Transaction will result in reduced ownership and influence of the existing shareholders

The Company will issue 816,198,842 new shares to NOR and Petromal as compensation for receiving all of the shares in PetroNor. The completion of the Transaction will therefore result in an increased number of shares in the Company, which again will cause a reduced ownership percentage of the Company's existing shareholders. The reduced ownership percentage will consequently result in reduced influence over matters submitted for vote in the general meetings of the Company, including but not limited to reduced influence over election of the members of the Company's board of directors (the "Directors" and "Board of Directors", respectively) and the distribution of dividends. Following completion, the current shareholders of the Company will hold approximately 16% of the shares in the Company.

1.5.4 Contracts held by PetroNor may not be transferred to the Company on the same terms

Certain third party consents, waivers and/or confirmations will be necessary to obtain in order to transfer some of PetroNor's contracts. The Company may not be able to obtain such necessary consents, waivers and/or confirmations or not be able to obtain such consents on terms as favourable as the current terms.

1.5.5 The closing of the Transaction is dependent on certain conditions being met

Under the Combination Agreement, the Transaction is conditional upon the satisfaction or waiver of a number of conditions beyond the control of the Company, as set out in Section 4.6 "Conditions". These conditions may not be met and the Transaction may hence not be consummated. Transaction costs, including costs of advisors, will regardless have incurred. In addition, the anticipated benefits of having completed the Transaction will not be realized and the failure to complete the Transaction might result in a negative perception by the stock market of the Company and consequently result in a decline of the Shares' market value.

1.5.6 The Company may discover contingent or other liabilities within PetroNor

The Company will acquire all of the shares in PetroNor "as is". The Company may discover liabilities or other issues relating to PetroNor that may have a material adverse effect on the Company's results, cash flow, business and financial condition. The warranties and indemnities from NOR and Petromal are limited, and the Company may not be entitled to seek remedy from NOR and Petromal.

1.5.7 PetroNor may not be granted a right to enter into the PNGF Bis licence

PetroNor has not been granted a right to enter into PNGF Bis and there is no guarantee that PetroNor will be granted such a right. PetroNor's right to PNGF Bis is strictly limited to a right to negotiate with the Republic of Congo the licence terms to enter into PNGF Bis. There can be no assurance that the negotiations will be successfully completed and that the parties will agree on the licence terms.

1.6 Risks related to the Shares

1.6.1 The Company will have two major shareholders

Following the completion of the Transaction, Petromal and NOR will own approximately 38% and 45% of the issued share capital of the Company, respectively. As major shareholders of the Company, Petromal and NOR will in their capacity as such have the ability to significantly influence the outcome of matters submitted for vote in the general meetings. The commercial goals and interests of Petromal and NOR as shareholders and the commercial goals and interest of the Company and/or the other shareholders may not always be aligned.

1.6.2 The price of the Shares may fluctuate significantly

The trading price of the Shares could fluctuate significantly in response to a number of factors beyond the Company's control, including quarterly variations in operating results, adverse business developments, changes in financial estimates and investment recommendations or ratings by securities analysts, significant contracts, acquisitions or strategic relationships, publicity about the Group, its services or its competitors, lawsuits against the Group, unforeseen liabilities, changes to the regulatory environment in which the Group operates or general market conditions.

In recent years, the stock markets have experienced extreme price and volume fluctuations. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in the same industry as the Company. Such changes may occur without regard to the operating performance of these companies. The price of the Shares may therefore also fluctuate significantly based upon factors that have little or nothing to do with the Company, and these fluctuations may materially affect the price of the Shares.

1.6.3 Future sale of the Shares by the Company's major shareholders or any of its primary insiders may depress the price of the Shares

Any sale by the Company's major shareholders or any sales of large number of Shares in the market, or the perception that such sales could occur, might result in a decline in the market price of the Shares. Such sales or possibility of such sales, might make it more challenging for the Company to sell equity shares at the time and price it deems appropriate.

1.6.4 Future issuances of Shares or other securities may significantly dilute the holdings of shareholders and could materially affect the price of the Shares

The Company may in the future decide, or may be required, to offer additional Shares or other securities in order to finance its operations, participation in new capital-intensive projects, or in connection with unanticipated liabilities, losses or expenses or for any other purposes. There are no provisions in the Company's Constitution or the Australian Corporations Act which grants pre-emptive rights for share issues. Therefore, any additional offering could significantly reduce the proportionate ownership and voting interests of holders of Shares, as well as the earnings per Share and the net asset value per Share of the Company, and any offering by the Company could have a material adverse effect on the market price of the Shares.

1.6.5 Investors may not be able to exercise their voting rights for Shares registered in a nominee account

Beneficial owners of the Shares that are registered in a nominee account (such as through brokers, dealers or other third parties) may not be able to vote for such Shares unless their ownership is re-registered in their names prior to the Company's general meetings. The Company cannot guarantee that beneficial owners of the Shares will receive the notice of a general meeting in time to instruct their nominees to either effect a re-registration of their Shares or otherwise vote for their Shares in the manner desired by such beneficial owners.

1.6.6 The transfer of Shares is subject to restrictions under the securities laws of the United States and other jurisdictions

The Shares have not been registered under the Securities Act or any US state securities laws or in any other jurisdiction outside of Australia and Norway and are not expected to be registered in any such jurisdiction in the future. As such, the Shares may not be offered or sold except pursuant to an exemption from the registration requirements of the Securities Act and applicable securities laws. Investors in the United States should proceed on the assumption that they must bear the economic risk of any investment in the Shares for an indefinite period of time. In addition, there can be no assurances that shareholders residing or domiciled in the United States will be able to participate in future capital increases or rights offerings in the Company.

1.6.7 Investors in the United States may have difficulty enforcing any judgment obtained in the United States against the Company or its Directors or executive officers

The Company is a public limited liability company incorporated under the laws of Australia, and none of the Company's Directors and executive officers are residents of the United States and all of the Company's assets are located outside the United States. As a result, investors in the United States may be unable to effect service of process on the Company or its Directors and executive officers or enforce judgments obtained in the United States courts against the Company or such persons in the United States, including judgments predicated upon the civil liability provisions of the federal securities laws of the United States. The United States does not currently have a treaty providing for reciprocal recognition and enforcement of judgments (other than arbitral awards) in civil and commercial matters with Australia or Norway.

1.6.8 Foreign ownership restrictions apply under Australian law

According to statutory Australian law, foreign ownership of substantial interests in Australian companies is subject to prior approval by the Australian Foreign Investment Review Board ("FIRB"). The regulation applies to all Australian incorporated companies valued in excess of AUD 252 million by either (i) market capitalisation and/or (ii) consolidated total assets on the balance sheet. Currently, the Company does not satisfy any of the two criteria. Accordingly, the Company is not presently required to notify and obtain the approval of FIRB in relation to an acquisition of shares which result in a foreign person acquiring a controlling interest in the Company.

In the event that any of the criteria is satisfied in the future, this will imply that prior approval by FIRB apply to certain foreign shareholdings in the Company. Prior approval is required for any foreign person, alone or together with its associates, acquiring a substantial interest, being 15% or more of the Shares in the Company. While prior notification is not mandatory for holdings by a foreign person of less than a substantial interest (15% or less) in the Company, the Australian Treasurer has the power to prohibit transactions, or order divestment where several foreign persons hold 40% or more of the Shares, even where those foreign persons are not associated, and where the Australian Treasurer is satisfied the result would be contrary to the Australian national interest.

While the Treasurer has the ability to block proposals that are contrary to the national interest, require such a transaction to be unwound or apply conditions to the way such a proposal is implemented, in practice this power is exercised only in limited circumstances. In determining if a proposal is contrary to the Australian national interest, the Treasurer takes into account a number of key factors, namely the impact of the proposal on Australian national security, impact on competition, impact on Australian government policies and impact on the Australian economy and community.

In addition, the Australian Treasurer has released a policy which states that all foreign government investors acquiring 10% or more of the share capital (including investments which are purely commercial) should notify the proposed acquisition to FIRB. This also applies to *inter alia* government related investment funds and managed investment schemes, provided that a foreign government holds 15% (or otherwise through a controlling group). If prior approval is required, the transaction cannot be completed until approval is received. FIRB has 30 days, with the option to extend for another 90 days, to consider and make a decision and other parties can make enquiries to FIRB to confirm whether they will need to apply for approval.

There can be no assurance that foreign shareholders subject to approval by FIRB will be granted approval to acquire Shares, and if such approval is not granted any transactions entered into for such purpose will need to be reversed. The Company will not be liable for any loss or damage resulting from such denial of approval.

1.6.9 Shareholders outside of Australia are subject to exchange rate risk

Any payments of dividends on the Shares may be declared by the Company in USD or AUD; however, such dividends distributed by the Company's registrar in the Norwegian Central Securities Depository (the "VPS"), being DNB Bank ASA (the "VPS Registrar"), through the VPS to shareholders with an address in Norway or shareholders holding NOK bank accounts will be distributed in NOK. Shareholders registered in the VPS and whose address is outside Norway and who have not supplied the VPS with details of any NOK account, will receive dividends by cheque in a local currency or in USD (following first conversion to NOK). Accordingly, the investors are subject to adverse movements in AUD, NOK and/or USD against their local currency.

1.6.10 Risks related to depository receipts and the registrar agreement

In connection with the Company's listing on Oslo Axess, the Company established a facility for the registration of beneficial interests representing the shares of the Company in the VPS (reflected in the form of Depositary Receipts and defined as "Shares" in this Information Memorandum). The Company has appointed DNB Bank ASA as its VPS Registrar in accordance with the Registrar Agreement. The VPS Registrar will be deemed a beneficial shareholder through a nominee arrangement with Citibank Melbourne (the "Australian Custodian") where the Australian Custodian is recorded as the shareholder in the Company's Issuer Sponsored Sub-register.

Shareholders must exercise voting rights through the VPS Registrar which in turn will instruct the Australian Custodian. Exercising of other shareholder rights through the VPS Registrar and the custodian arrangement is limited. In order to exercise full shareholder rights the shareholders must transfer their shareholding from the VPS to a registered holding on the Company's share register.

The Company cannot guarantee that the VPS Registrar will be able to execute its obligations under the Registrar Agreement. Any such failure may *inter alia* limit the access for, or prevent, shareholders to exercise the voting rights attached to the underlying shares of the Company. The VPS Registrar may terminate the Registrar Agreement by three months prior written notice. Furthermore, the VPS Registrar may terminate the Registrar Agreement with immediate effect if the Company does not fulfil its payment obligations to the VPS Registrar or commits any other material breach of the Registrar Agreement. In the event that the Registrar Agreement is terminated, the Company will use its reasonable best efforts to enter into a replacement agreement for purposes of permitting the uninterrupted listing on Oslo Axess. There can be no assurance, however, that it would be possible to enter into such an agreement on substantially the same terms or at all. A termination of the Registrar Agreement could, therefore, materially and adversely affect the Company and the shareholders. The Registrar Agreement limits the VPS Registrar's liability for any loss suffered by the Company. The VPS Registrar disclaims any liability for any loss attributable to circumstances beyond the VPS Registrar's control, including, but not limited to, errors committed by others. The VPS Registrar is liable for direct losses incurred as a result of the VPS Registrar's negligence. Thus, the Company and the shareholders may not be able to recover its entire loss if the VPS Registrar does not perform its obligations under the Registrar Agreement.

1.6.11 The Company is incorporated in Australia and governed by Australian law

The Company is incorporated in Australia. As a result, the rights of any person holding Shares will be governed by the laws of Australia and the Constitution of the Company. The laws of Australia differ from those established under statutes or judicial precedents in existence in other jurisdictions. Such differences may result in the Company's minority shareholders having less protection than they would have under the laws of other jurisdictions.

2 RESPONSIBILITY STATEMENT

This Information Memorandum has been prepared by African Petroleum Corporation Limited to provide information regarding the Transaction.

The Board of Directors of African Petroleum Corporation Limited accepts responsibility for the information contained in this Information Memorandum. The members of the Board of Directors confirm that, after having taken all reasonable care to ensure that such is the case, the information contained in this Information Memorandum is, to the best of their knowledge, in accordance with the facts and contains no omission likely to affect its import.

29 March 2019

The Board of Directors of African Petroleum Corporation Limited

David King	*Jens Pace*	*Stephen West*
Chairman	*Director*	*Director*

Bjarne Moe	*Timothy Turner*
Director	*Director*

3 GENERAL INFORMATION

3.1 Industry and market data

In this Information Memorandum, the Company has used industry and market data obtained from independent industry publications, market research and other publicly available information.

While the Company has complied, extracted and reproduced industry and market data from external sources, the Company has not independently verified the correctness of such data. The Company cautions prospective investors not to place undue reliance on the above mentioned data. Unless otherwise indicated in the Information Memorandum, the basis for any statements regarding the Group's competitive position is based on the Company's own assessment and knowledge of the potential market in which it operates.

The Company confirms that where information has been sourced from a third party, such information has been accurately reproduced and that as far as the Company is aware and is able to ascertain from information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading. Where information sourced from third parties has been presented, the source of such information has been identified, however, source references to websites shall not be deemed as incorporated by reference to this Information Memorandum. The Company does not intend, and does not assume any obligations to update industry or market data set forth in this Information Memorandum.

Industry publications or reports generally state that the information they contain has been obtained from sources believed to be reliable, but the accuracy and completeness of such information is not guaranteed. The Company has not independently verified and cannot give any assurances as to the accuracy of market data contained in this Information Memorandum that was extracted from these industry publications or reports and reproduced herein. Market data and statistics are inherently predictive and subject to uncertainty and not necessarily reflective of actual market conditions. Such statistics are based on market research, which itself is based on sampling and subjective judgments by both the researchers and the respondents, including judgments about what types of products and transactions should be included in the relevant market.

As a result, prospective investors should be aware that statistics, data, statements and other information relating to markets, market sizes, market shares, market positions and other industry data in this Information Memorandum (and projections, assumptions and estimates based on such information) may not be reliable indicators of the Company's future performance and the future performance of the industry in which it operates. Such indicators are necessarily subject to a high degree of uncertainty and risk due to the limitations described above and to a variety of other factors, including those described in Section 1 "Risk factors" and elsewhere in this Information Memorandum.

3.2 Rounding

Certain figures included in this Information Memorandum have been subject to rounding adjustments (by rounding to the nearest whole number or decimal or fraction, as the case may be). Accordingly, figures shown for the same category presented in different tables may vary slightly. As a result of rounding adjustments, the figures presented may not add up to the total amount presented.

3.3 Other information

In this Information Memorandum, all references to "NOK" are to the lawful currency of Norway, all references to "USD" or "U.S. Dollar" are to the lawful currency of the United States, all references to "AUD" are to the lawful currency of Australia. No representation is made that the NOK, USD or AUD amounts referred to herein could have been or could be converted into NOK, USD or AUD as the case may be, at any particular rate, or at all.

3.4 Cautionary note regarding forward-looking statements

This Information Memorandum includes forward-looking statements that reflect the Company's current views with respect to future events and financial and operational performance. These forward-looking statements may be identified by the use of forward-looking terminology, such as the terms "anticipates", "assumes", "believes", "can", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "should", "projects", "will", "would" or, in each case, their negative, or other variations or comparable terminology. These forward-looking statements as a general matter are all statements other than statements as to historic facts or present facts and circumstances. They appear in the following Sections in this Information Memorandum, Section 4 "Description of the Transaction", Section 5 "Presentation of African Petroleum", Section 6 "African Petroleum selected financial information", Section 7 "Industry overview" and Section 8 "Presentation of PetroNor", and include statements regarding the Company's intentions, beliefs or current expectations concerning, among other things, financial strength and position of the Group, operating results, liquidity, prospects, growth, the implementation of strategic initiatives, as well as other statements relating to the Group's future business development and financial performance, and the industry in which the Group operates.

Prospective investors in the Shares are cautioned that forward-looking statements are not guarantees of future performance and that the Group's actual financial position, operating results and liquidity, and the development of the industry and potential market in which the Group may operate in the future, may differ materially from those made in, or suggested by, the forward-looking statements contained in this Information Memorandum. The Company cannot guarantee that the intentions, beliefs or current expectations upon which its forward-looking statements are based will occur.

By their nature, forward-looking statements involve, and are subject to, known and unknown risks, uncertainties and assumptions as they relate to events and depend on circumstances that may or may not occur in the future. Because of these known and unknown risks, uncertainties and assumptions, the outcome may differ materially from those set out in the forward-looking statements.

The information contained in this Information Memorandum, including the information set out under Section 1 "Risk factors", identifies additional factors that could affect the Group's financial position, operating results, liquidity and performance. Prospective investors in the Shares are urged to read all Sections of this Information Memorandum and, in particular, Section 1 "Risk factors" for a more complete discussion of the factors that could affect the Group's future performance and the industry in which the Group operates when considering an investment in the Company.

These forward-looking statements speak only as at the date on which they are made. The Company undertakes no obligation to publicly update or publicly revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to the Company or to persons acting on the Company's behalf are expressly qualified in their entirety by the cautionary statements referred to above and contained elsewhere in this Information Memorandum.

4 DESCRIPTION OF THE TRANSACTION

4.1 Overview of the Transaction

The Company entered into an agreement on 19 March 2019 with NOR and Petromal to combine with PetroNor. Following the completion of the Transaction, the Company shall change its name to PetroNor E&P Ltd.

NOR and Petromal shall upon completion of the Transaction transfer all of their shares in PetroNor, constituting 100% of the issued and outstanding share capital of PetroNor, to the Company against the delivery by the Company of 816,198,842 Consideration Shares in the Company. The Consideration Shares shall on a diluted basis represent 84% of the total issued and outstanding Shares in the Company. Following completion of the Transaction, the current shareholders of the Company will hold on a diluted basis the remaining 16% of all issued and outstanding shares. The total amount of issued and outstanding Shares in the Company following completion of the Transaction will be 971,665,288.

4.2 The Parties to the Transaction

The Company is an oil and gas exploration and development company focused on exploration offshore West Africa. The Company holds a total of four licence blocks offshore The Gambia and Senegal, giving the Company a total combined gross exploration licence acreage of 18,468 km^2. See Section 5 "Presentation of African Petroleum" for further information about the Company.

PetroNor is a privately held, Africa focused E&P independent, which is owned 50% by Petromal (economic benefit interest 45.572%) and 50% by NOR (economic benefit interest 54.428%). Petromal is an Abu Dhabi based integrated oil and gas company with operations and investments in the upstream, downstream, oil field service and EPC sectors. NOR is a Norwegian upstream oil and gas E&P company with its history from the North Sea and Africa.

PetroNor holds a 10.5% indirect interest in PNGF Sud and has a right under the umbrella agreement related to PNGF Sud, to in good faith negotiate with the Republic of Congo an entry into a 14.7% indirect interest in PNGF Bis. Following finalisation of licence terms for PNGF Bis, the combined Company intends to enter into a production sharing contract for this license, with Perenco as the operator. See Section 8 "Presentation of PetroNor" for further information about PetroNor and Petromal and NOR.

4.3 Background and reason for the Transaction

With the continued uncertainty related to African Petroleum's licences in The Gambia and Senegal (the "Existing Assets"), the Company believes that the Transaction will bring stability and downside protection to the Company, while maintaining substantial upside potential towards the Existing Assets. Additionally, through additional competence, contacts and resources brought to the Company by PetroNor, the Transaction is expected to have a positive impact on African Petroleum's ongoing arbitration and farm-down processes related to the Existing Assets. Furthermore, following the Transaction, the Company will generate substantial free cash flow that can be reinvested into value accretive growth, including, but not limited to, the Existing Assets. Potential upside from the exploration portfolio is preserved through issuance of 155,466,446 warrants to the existing African Petroleum shareholders. Through the Transaction, African Petroleum will acquire diversified, low risk, long life and high quality producing assets with competitive unit costs and a well-regarded, efficient operator (Perenco). The Transaction will transform the Company from a pure-play exploration company into a full cycle E&P company with material reserves, cash flow and significant upside potential.

The Congo Assets, which are located in shallow waters offshore Congo (Brazzaville), have net 2P reserves estimated to approximately 8.5 mmbo and net production of approximately 2,300 bopd from four fields currently in production, in addition to net 2C contingent resources of 7.6 mmbo as at 1 January 2019.[1] In addition to the Congo Assets, PetroNor is assessing new opportunities in Africa with significant upside potential from contingent resources to be developed.

4.4 Consideration

As consideration for the transfer of all the shares in PetroNor to the Company, NOR and Petromal shall upon completion of the Transaction receive 816,198,842 Consideration Shares in the Company.

In connection with the Transaction, existing shareholders of African Petroleum at the date of the general meeting required to approve the Transaction (as reflected in the shareholder register and in the VPS on 26 April 2019 the ("Record Date") (the "Eligible APCL Shareholders"), will receive one (1) warrant per existing share held in the Company, in total 155,466,446 warrants (the "APCL Warrants").

The APCL Warrants will vest upon (x) either (a) the reinstatement of the A1 and A4 licences in The Gambia or (b) the reinstatement of the SOSP licence in Senegal, whichever comes first, and (y) a farm-in agreement to such licence(s) being signed and legally binding, where the Company will be fully carried for the current phase work program under the licence(s), on commercially acceptable terms approved by the Board of Directors (the "APCL Warrants Vesting Event"). The APCL Warrants will lapse without compensation to the holder(s) if the APCL Warrants Vesting Event has not occurred by 31 December 2019. The APCL Warrants will not be listed or tradable and shares issued pursuant to the APCL Warrants will not be listed or tradable until the APCL Warrants Vesting Event has occurred and the APCL Warrants have been exercised accordingly.

Additionally, PetroNor shareholders, being NOR and Petromal, will receive in total 155,466,446 warrants related to a business development opportunity offshore Nigeria which is in an advanced phase of negotiations (the "PetroNor Warrants"). The Petronor Warrants will vest upon (x) a signed acquisition/farm-in agreement for a gas asset in Nigeria, and (y) a signed and legally binding gas offtake agreement relating to the gas from such asset, both agreements on commercially acceptable terms approved by the Board of Directors (the "PetroNor Warrants Vesting Event"). The PetroNor Warrants will lapse without compensation to the holder(s) if the Petronor Warrants Vesting Event has not occurred by 31 December 2019. The PetroNor Warrants will not be listed or tradable and shares issued pursuant to the PetroNor Warrants will not be listed or tradable until the PetroNor Warrants Vesting Event has occurred and the PetroNor Warrants have been exercised accordingly.

In addition, 15,740,000 existing options issued to the Board, Management and consultants of African Petroleum will be replaced with 8,513,848 new performance options with the same vesting conditions as the APCL Warrants (the "APCL Replacement Performance Options").

Following completion of the Transaction, African Petroleum will have a total of 971,665,288 outstanding shares and 322,817,378 warrants, whereof existing shareholders of African Petroleum will hold 155,466,446 outstanding shares and 155,466,446 warrants, and existing Directors, Management members and consultants will hold 8,513,848 APCL Replacement Performance Options. Prior to the exercise of any warrants, existing shareholders of African Petroleum will hold 16% of the shares of the Company and existing shareholders of PetroNor will hold 84% of the shares.

[1] Part of the 2C resources relate to the unacquired PNGF Bis license.

The below table sets out the warrants and options which will be in issue in the Combined Company as per completion of the Transaction:

Expiry date	Exercise price (NOK – unless otherwise noted)	Number	Vesting condition	Holders
22 Apr 2019	A$3.00	17,501	None	Former employees
3 Jun 2019	A$2.40	50,000	None	Former employees
5 Jun 2019	A$3.00	20,000	None	Former employees
15 Dec 2019	A$3.00	16,667	None	Former employees
28 Apr 2020	4.00	987,000	None	Former employees
15 Nov 2020	1.70	190,000	None	Former employees
22 Dec 2020	1.70	700,000	None	Former employees
11 Jan 2022	2.50	213,400	None	Company brokers
31 May 2022	7.75	1,176,070	None	Company brokers
31 Dec 2019	0.00	155,466,446	PetroNor Warrants Vesting Event	NOR and Petromal
31 Dec 2019	0.00	155,466,446	APCL Warrants Vesting Event	Pre-existing African Petroleum shareholders
31 Dec 2019	0.00	8,513,848	APCL Warrants Vesting Event	African Petroleum Board, management and consultants
Total		**322,817,378**		

Post exercise of all warrants and options (excluding options under any employee incentive program which is expected to be proposed for approval by the shareholders post-closing of the Transaction), existing shareholders and option holders of APCL will hold ~24.9% of the Shares of the Company and existing shareholders of PetroNor will hold ~75.1%. Following completion of the Transaction, a new incentive program for the Company's management and employees will be established.

In connection with the Transaction, each of NOR, Petromal as well as the Chief Executive Officer Mr. Jens Pace and Chief Financial Officer Mr. Stephen West of African Petroleum have undertaken a six months lock-up for all of their shares to the benefit of the Company.

Other than the granting of the PetroNor Warrants and Performance Warrants, no agreements have or will be entered into in connection with the transaction for the benefit of the Company's senior employees or members of the board of directors or for the senior employees or board of directors of PetroNor.

4.5 Completion

The completion of the Transaction shall be by way of:

(a) each of NOR and Petromal delivering the shares in PetroNor to the Company; and

(b) the Company issuing an irrevocable written, instruction to Computershare to issue the Company Shares to each of NOR and Petromal, through issuance to Citicorp and instruction to DNB to convert the Company Shares into depositary receipts in the VPS.

4.6 Conditions

The Transaction is subject to customary closing conditions, including:

(a) Approval by the shareholders of African Petroleum eligible to vote at the EGM with requisite majority (greater than 50% of shareholders voting at the EGM), including approval of the acquisition of a relevant interest in the Company by Petromal and NOR and issuance of the warrants;

(b) A confirmation by the Oslo Stock Exchange that the listing status of African Petroleum will be maintained following completion of the Transaction;

(c) No material adverse effect with respect to PetroNor or its business having occurred; and

(d) No material adverse effect with respect to African Petroleum having occurred.

4.7 Description of the Consideration Shares and VPS registration

The Underlying Shares

The Consideration Shares will be issued in accordance with the laws of Australia and pursuant to the Australian Corporations Act. It is expected that the underlying Shares will be issued to the Australian Custodian on behalf of the VPS Registrar on or about 30 April 2019.

The Consideration Shares will be issued in book-entry form and registered in the Company's Issuer Sponsored Sub-register, and thereafter registered with the VPS as Depository Receipts.

The underlying shares and the Depository Receipts will have ISIN AU000000AOQ0. The Company's share capital is nominated in AUD, but the Shares have no par value. The Company's share registrar in Australia is Computershare. The address of Computershare is:

Computershare Investor Services Pty Ltd
Level 11, 172 St George's Terrace
Perth, Western Australia, 6000
Australia

Depository Receipts

In order to enable trading of the Consideration Shares on Oslo Axess, the Consideration Shares will be issued to Petromal and NOR in the VPS in the form of Depository Receipts. The Depository Receipts will be issued under Norwegian law and will be registered in book entry form with the VPS. DNB Bank ASA, in its capacity as the VPS Registrar will be holding the New Shares in the Issuer Sponsored Sub-register through a nominee arrangement with the Australian Custodian who will be recorded as the legal holder of the New Shares. The currency of the Depository Receipts will be in NOK.

The Depository Receipts carry the same rights as the underlying Shares, provided however, that the exercise of voting rights and other shareholder rights by holders of the Depository Rights must be made indirectly through the VPS Registrar.

It is expected that the Depository Receipts will be issued on or about 30 April 2019.

All references to Consideration Shares in this Information Memorandum is a reference to the beneficial rights in the Consideration Shares, unless otherwise indicated.

4.8 Rights conferred by the Consideration Shares

The Consideration Shares will rank *pari passu* in all respects with the existing Shares of the Company and will carry full shareholder rights in the Company from the time of issuance. The Consideration Shares will be eligible for any dividends declared by the Company after said registration. All Shares, including the Consideration Shares, will have voting rights and other rights and obligations pursuant to the laws of Australia, and are governed by Australian law. Generally, all Shares are freely transferable, subject to the registration of the transfer not resulting in a contravention of a failure to observe the provisions of a law of Australia and the transfer not being in breach of the Australian Corporations Act or applicable listing rules.

4.9 Resolutions pertaining to the issuance of the Consideration Shares, the PetroNor Warrants, the APCL Warrants and APCL Replacement Performance Options

It is proposed that the general meeting of the Company to be held on or about 24 April 2019 approves the issuance of the Consideration Shares, the PetroNor Warrants, APCL Warrants and the APCL Replacement Performance Options by adopting the following resolutions:

(a) *"That, for the purposes of Section 611 (Item 7) of the Corporations Act and for all other purposes, approval is given for the Company to issue:*

(i) *444,237,596 Shares in the Company to NOR Energy AS ("NOR Energy") and 371,961,246 Shares in the Company to Petromal – Sole Proprietorship LLC ("Petromal") (together, the "Consideration Shares");*

(ii) *104,162,519 warrants in the Company to NOR Energy ("NOR Warrants") and 51,303,927 warrants in the Company to Petromal ("Petromal Warrants") (jointly the "Petromal Warrants"); and*

(iii) *104,162,519 Shares in the Company to NOR Energy upon the exercise of the NOR Warrants and 51,303,927 Shares in the Company to Petromal upon the exercise of the Petromal Warrants, both as referred to in paragraph (b) above,*

on the terms and conditions set out in the Explanatory Statement, which will result in the voting power of NOR Energy in the capital of the Company increasing from nil to 48.65% and the voting power of Petromal in the capital of the Company increasing from nil to 37.55% following the issue of the Consideration Shares and the Petronor Warrants, on the assumption that there have not been any changes to the issued share capital of the Company at the time of exercise of the Petronor Warrants, (otherwise prohibited by section 606(1) of the Corporations Act)."

(b) *"That, subject to the passing of Resolution 1, approval is given for the Company to issue:*

(i) *155,466,446 warrants allocated among existing Shareholders of the Company as at the date of the General Meeting, and for the Company's Shares registered in the VPS, as reflected in the VPS on a customary T+2 basis (the "Company Warrants"); and*

(ii) *8,513,848 warrants to the existing Optionholders as at the date of the Combination Agreement entered into by, inter alia, the Company (the "Replacement Warrants"),*

on the terms and conditions set out in the Explanatory Statement."

4.10 Completion of the Transaction, issuance, delivery and listing of the Consideration Shares

It is currently expected that the completion of the Transaction will take place on or about 30 April 2019, immediately following which (i) the Consideration Shares will be issued and delivered to NOR and Petromal, and become listed and tradable on Oslo Axess and (ii) the APCL Warrants, the PetroNor Warrants and the APCL Replacement Performance Options will be issued to each of the Eligible APCL Shareholders, NOR and Petromal and the members of the executive management of African Petroleum entitled to receive the APCL Replacement Performance Options.

4.11 Expenses relating to the Transaction

The Company's expenses relating to the Transaction, primarily fees to the Company's and PetroNor's advisors, are currently estimated to NOK 18.2 million. Additional expenses may be incurred in relation to the Transaction.

4.12 Interests of certain persons in the Transaction

Except for the granting of the PetroNor Warrants and the APCL Replacement Performance Options as described in Section 4.4 "Consideration", no agreements to the benefit of the members of the Board of Directors or management of African Petroleum or PetroNor have been, or are expected to be, entered into as a result of the Transaction.

4.13 Advisors

Pareto Securities AS is acting as the Company's financial advisor in connection with the Transaction. Arctic Securities AS is acting as PetroNor's financial advisor in connection with the Transaction.

Arntzen de Besche Advokatfirma AS is acting as Norwegian legal counsel and Steinepreis Paganin is acting as Australian legal counsel to the Company in connection with the Transaction. Advokatfirmaet Schjødt AS is acting as Norwegian legal counsel to PetroNor.

5 PRESENTATION OF AFRICAN PETROLEUM

5.1 Name, incorporation and registered office

The Company's registered name is African Petroleum Corporation Limited. African Petroleum is a public limited liability company, established under the laws of Australia. The Company is subject to the Australian Corporations Act. The Company was incorporated 16 May 2007 under the name Global Iron Limited ("Global Iron") and changed its name to African Petroleum Corporation Limited on 24 June 2010, after a reverse take-over by African Petroleum Corporation Limited (Cayman Islands). The Company is registered with the Australian Securities and Investments Committee ("ASIC") under organization number ACN 125 419 730. The Company's registered business address is Level 4, 16 Milligan Street, Perth, WA 6000, Australia. The principal offices of the Company are located in London, at 48 Dover Street, London, W1S 4FF, United Kingdom. The telephone number is +44 (0) 203 655 7810. The Company's website can be found at www.africanpetroleum.com.au. The Company has been listed on Oslo Axess since May 2014.

5.2 History of the Group

The Company was incorporated in Australia on 16 May 2007 and admitted to the official list of ASX on 16 October 2007. However, the current business of the Company dates back to June 2005 when European Hydrocarbons Limited ("EHL") and Regal Liberia Ltd, following an international bidding round, were awarded 75 per cent and 25 per cent working interest respectively in licences LB-09 and LB-08 offshore Liberia. In November 2007, EHL acquired the remaining 25 per cent interest in licences LB-08 and LB-09 indirectly through its acquisition of Regal Liberia Ltd.

In 2010 a reverse take-over, resulting in the assets of EHL being transferred to Global Iron, was completed through the following steps:

(i) On 28 January 2010, EHL completed a reverse takeover of European Hydrocarbons Limited (Cayman Islands).

(ii) On 29 January 2010, European Hydrocarbons Limited (Cayman Islands) completed a reverse takeover of African Petroleum Corporation Limited (Cayman Islands).

(iii) On 30 June 2010, African Petroleum Corporation Limited (Cayman Islands) completed a reverse takeover of Global Iron.

The reverse take-over described in item (iii) above was conducted by African Petroleum Corporation Limited (Cayman Islands) completing the acquisition of Global Iron in conjunction with a USD 222 million fundraising pursuant to a placement of new shares directed at professional and institutional investors.

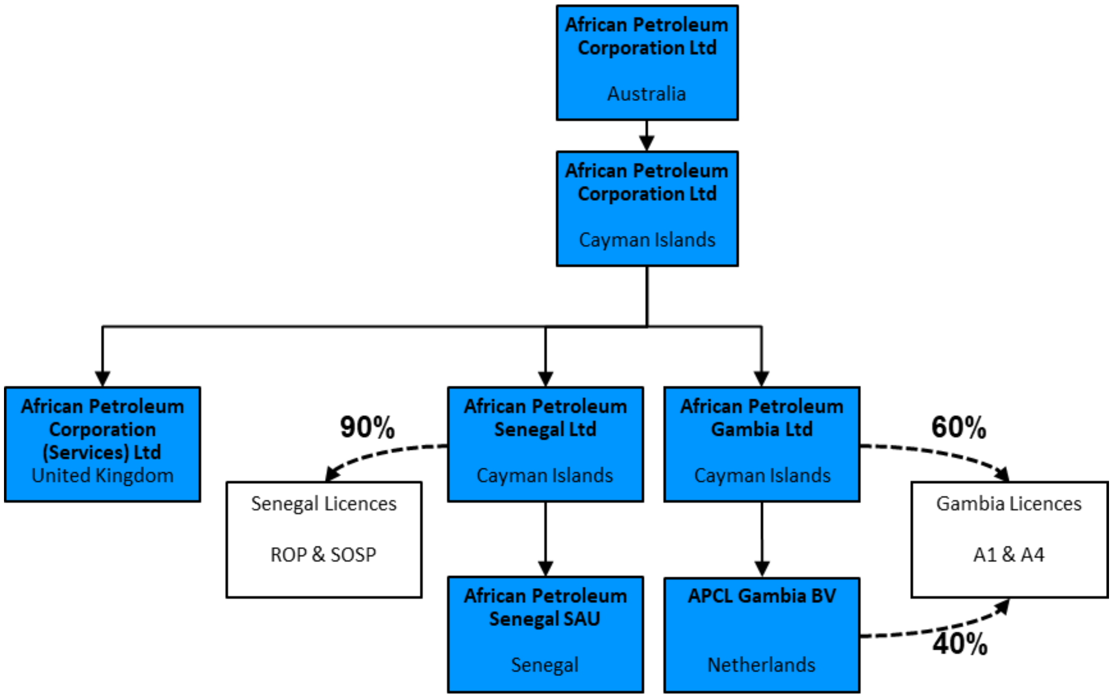
Following the reverse takeover, the Company was admitted to the official list on NSX on 30 June 2010 and subsequently delisted from the ASX following application from the Company on 3 September 2010.

The Company's securities were admitted for trading on the Oslo Axess on 30 May 2014. The Company voluntarily de-listed from the NSX with effect from 4 January 2016.

5.3 Legal structure

The Company is the ultimate parent company of the Group. In addition, the Group consists of 17 subsidiaries. The majority of the Group's subsidiaries are incorporated on the Cayman Islands, except for certain companies incorporated in the countries where the Group conducts its activities through its licences, as well as 4 subsidiaries incorporated in the UK, including the management company African Petroleum Corporation (Services) Limited.

The figure below sets forth a condensed legal structure of the Group:



The table below contains a list of all of the Company's subsidiaries:

Company name	Country of incorporation	Group ownership
African Petroleum Corporation Limited	Cayman Islands	100%
European Hydrocarbons Limited	Cayman Islands	100%
European Hydrocarbons SL Limited	Cayman Islands	100%
African Petroleum Drilling Services Limited	Cayman Island	100%
African Petroleum Sierra Leone Limited	Cayman Islands	100%
African Petroleum Senegal Limited	Cayman Islands	90%[1]
African Petroleum Gambia Limited	Cayman Islands	100%
African Petroleum Côte d'Ivoire Limited	Cayman Islands	100%
African Petroleum (SL) Limited	Sierra Leone	99.99%[2]
European Hydrocarbon (SL) Limited	Sierra Leone	99.99%[2]
African Petroleum Senegal SAU	Senegal	100%
African Petroleum Côte d'Ivoire SAU	Côte d'Ivoire	100%
African Petroleum Corporation (Services) Limited	United Kingdom	100%
European Hydrocarbons Limited	United Kingdom	100%
Regal Liberia Limited	United Kingdom	100%
African Petroleum Corporation Limited	United Kingdom	100%
APCL Gambia B.V.	Netherlands	100%

1 Remaining 10% shareholding held by Prestamex Limited

2 Remaining 0.01% shareholding held by the deceased estate of Mr. Bangura (a former director of the Company).

5.4 The business of the Group

5.4.1 Introduction

The Group is an oil and gas exploration and development group focused on exploration offshore West Africa. The Group holds a total of four licence blocks offshore The Gambia and Senegal, giving the Company a total combined gross exploration licence acreage of 18,468 km^2.

The Company is the ultimate holding company of the Group, and has no operational activities. The subsidiaries, African Petroleum Senegal Limited and African Petroleum Gambia Limited conduct activities through licences in the countries reflected by the company names.

The Group's exploration activities have so far been financed by equity capital and the Company has raised a total of USD 615.9 million through the completion of nine capital raisings in 2010, 2011, 2012, 2014, 2015 and 2017.

The Group has drilled three wells in offshore Liberia and one well in offshore Côte d'Ivoire; however, the Company did not announce a discovery that is estimated to be possible to develop commercially and the licences held by the Company in Liberia and Côte d'Ivoire were subsequently relinquished.

The Group has 3D seismic data available for all of its four licences. The Senegal ROP Licence 3D seismic data was purchased from Société des Pétroles du Sénégal, the national oil company of Senegal ("Petrosen") and the Group acquired new 3D seismic surveys on the remaining three licences as part of agreed minimum work commitments.

5.4.2 Overview of the Company's operations

The Company has established itself as an oil and gas exploration company in West Africa. The Company, through its subsidiaries, hold four hydrocarbon exploration licences offshore West Africa, two licences in each of The Gambia and Senegal with a combined gross acreage of 18,468 km^2. The Group has 3D seismic data available for all of its four licences. The Senegal ROP Licence 3D seismic data was purchased from Petrosen and the Group has acquired new 3D seismic surveys on the remaining three licences as part of agreed minimum work commitments.

The Group previously held two licences in Liberia; however, following the drilling of three offshore wells in Liberia with encouraging but inconclusive results and the licences in Liberia were relinquished in 2015. Further, the Group previously held two licences in Côte d'ivoire and, following the successful farm-out of a 45% interest in one of the licences to Ophir Energy in December 2015, the Group drilled an unsuccessful exploration well in 2017 which led to the Group relinquishing its licences in Côte d'Ivoire in 2018. Further, the Group previously held two ultra-deep water licences in Sierra Leone which, following an unsuccessful farm-out process to secure a partner to drill an exploration well, the Group relinquished its interests in November 2018.

The Group is currently in dispute with the government of The Gambia regarding the status of the A1 and A4 licences. In October 2017, the Group's wholly-owned subsidiaries African Petroleum Gambia Limited and APCL Gambia B.V lodged Requests for Arbitration ("RFA") documents with the International Centre for ICSID in order to protect its interests in the A1 and A4 licences in The Gambia. The tribunal for the case was constituted on 26 March 2018 with the first session held on 27 June 2018. The Group filed its memorial on admissibility, jurisdiction and the merits of its case on 28 February 2019.

Further, the Group is currently in dispute with the government of Senegal regarding the status of the ROP and SOSP PSCs. In January 2018 the Group's wholly owned subsidiary African Petroleum Senegal Limited lodged RFA documents with ICSID in order to protect its interests in the ROP and SOSP PSCs in Senegal. The tribunal for the case was constituted on 23 January 2019 with the first session held on 19 March 2019.

As part of the Company's business strategy, it is seeking to resolve the disputes with the governments of The Gambia and Senegal through the arbitration process. In the event that the Group is successful in resolving the licence disputes, it will be actively exploring farm-outs in order to reduce its working interest in some or all of its exploration licences. The farm-out process is part of a process of maturing the Group's asset portfolio and is initiated to *inter alia* reduce the Group's capital commitments, generate cash sales proceeds for funding of future operations as well as introducing technically and operationally competent joint venture partners to the Group's licences. The drilling of wells will require substantial financial resources relative to the economics of the Group, and the Group is dependent on completing farm-outs or alternative financing in order to complete the expected minimum work commitments under the various licences if they are re-instated. The Group intends to fund its future drilling commitments through farm-out agreements.

As described above, funds required for the acquisition of licences or for exploration work have historically been raised through equity raisings and one farm-out transaction that completed in 2016. Going forward the Group plans to fund its exploration and development activities, including drilling commitments, through further equity raisings and by farming out interests in licences to strategic partners, together with obtaining debt financing where available and appropriate.

Going forward, the focus of the Company will be dependent on the outcome of the arbitration proceedings underway in relation to its licences in The Gambia and Senegal. Should the Company be successful in the arbitration proceedings and the licences re-instated, it will pursue a farm-out on all of the Group's licences in order to fund drilling operations. Following re-instatement of the licences, should the Group not be able to secure financing through farm-out agreements in time or obtain extensions on the drilling commitments under the relevant licences when necessary, the licences may be revoked.

5.4.3 Senegal

In Senegal, African Petroleum Senegal Limited holds a 90% operated working interest in exploration blocks ROP and SOSP. Petrosen holds the remaining 10% equity. The Company's Senegal PSCs are located offshore southern and central Senegal, with a net acreage of 14,216km^2.

The current phase of the ROP PSC ended in October 2015; however, the Company lodged a request for an extension with the Government of Senegal. Under the terms of the ROP PSC the block remains active unless and until a termination procedure is enacted by the Republic of Senegal. To date, the Republic of Senegal has not validly enacted such termination procedure, and accordingly the Company reserves its rights under the ROP PSC.

A new PSC covering the same area as the ROP PSC was awarded to Total in 2017 and subsequently farmed down to Petronas in August 2018. Irrespective of this, the Company reserves its right under its ROP PSC.

The Company elected to move into the next phase of the SOSP PSC in late 2017 and requested that the outstanding drilling commitment in the expiring phase be transferred to the next phase as a seismic commitment. To date, the Republic of Senegal has not responded to this request and accordingly the Company reserves its rights under the SOSP PSC.

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

The Group is currently in dispute with the government of Senegal regarding the status of the ROP and SOSP PSCs and ICSID arbitration proceedings are underway. See Section 5.7 "Legal and Arbitration proceedings" for further details.

5.4.4 The Gambia

African Petroleum holds a 100% operated working interest in offshore licences A1 and A4, with a combined net acreage of 2,672km². The Company has completed a 3D seismic survey with data covering 2,500km² and has found a number of analogous leads and prospects in its acreage to that of the recent SNE and FAN discoveries drilled by Cairn Energy in Senegal.

The current phase of the A1 and A4 licences required the Company to drill an exploration well on either of the licences no later than 1 September 2016. The Company was unable to meet this drilling commitment and was, prior to the current dispute that led to the initiation of arbitration proceedings, in dialogue with the Government of The Gambia regarding the transfer of the outstanding drilling commitment into the next phase and entry into the next phase of the licences.

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

The Group is currently in dispute with the government of The Gambia regarding the status of the A1 and A4 licences and ICSID arbitration proceedings are underway. See Section 5.7 "Legal and Arbitration proceedings" for further details.

5.4.5 Competitors

The Company holds PSCs and licences in one of the most active offshore exploration areas in the world. Accordingly, there are a number of major international oil companies and large independent oil companies operating in the Company's areas of interest.

5.5 Material contracts

The Company is dependent on the following contracts, which are deemed material to the business of the Group:

5.5.1 PSCs and other contracts relating to the Group's current and previous licences

The Group's main contracts are the PSCs and other licences under which the Group holds interests in its exploration blocks. PSCs are common contracts signed between a government and a resource extraction company and the Group has entered into a number of PSCs with the respective governments in the different countries in which the Group holds its licences:

- **ROP:** The Hydrocarbon Exploration and Production Sharing Contract between the Republic of Senegal, Petrosen and African Petroleum Senegal Limited over licence Rufisque Offshore Profond, Senegal, dated 25 October 2011, for an initial research phase of up to 8 years and a subsequent exploitation phase of 25 years (that may be extended a further 10 years if necessary). The PSC is in the first exploration phase which ended in October 2015; however, the Company has lodged a request for an 18 month extension with the government. The Group is currently in dispute with the government of Senegal regarding the status of the ROP PSC and ICSID arbitration proceedings are underway to resolve the dispute (see Section 5.7 "Legal and arbitration proceedings");

- **SOSP:** The Hydrocarbon Exploration and Production Sharing Contract between the Republic of Senegal, Petrosen and African Petroleum Senegal Limited over the Senegal licence Offshore Sud Profond and dated 25 October 2011, amended on 30 October 2014, for an initial research phase of up to 8 years and a subsequent exploitation phase of 25 years (that may be extended a further 10 years if necessary). The PSC was in the first renewal period which ended on 25 October 2017; however, the Company elected to move into the next phase of the SOSP PSC in late 2017 and requested that the outstanding drilling commitment in the expiring phase be transferred to the next phase as a seismic commitment. To date, the Republic of Senegal has not responded to this request and accordingly the Company reserves its right under the SOSP PSC. The Group is currently in dispute with the government of Senegal regarding the status of the SOSP PSC and ICSID arbitration proceedings are underway to resolve the dispute (see Section 5.7 "Legal and arbitration proceedings");

- Joint operating agreements entered into on 25 November 2011 between Petrosen and African Petroleum Senegal Limited regarding licence ROP and licence SOSP;

- **A1:** Petroleum agreement entered into between the Government of the Republic of The Gambia, APCL Gambia BV and African Petroleum Gambia Limited over Alhamdulilah Licence Block A1 and dated 31 December 2007, amended on 27 November 2014, and is valid for a 30 year term. The licence is currently in the initial exploration phase which expired on 1 September 2016. The Group is currently in dispute with the government of The Gambia regarding the status of the A1 licence and the ICSID arbitration proceedings are underway to resolve the dispute (see Section 5.7 "Legal and arbitration proceedings"); and

- **A4:** Petroleum agreement entered into between the Government of the Republic of The Gambia, APCL Gambia BV and African Petroleum Gambia Limited over Alhamdulilah Licence Block A4 and dated 31 December 2007, amended on 27 November 2014, and is valid for a 30 year term. The licence is currently in the initial exploration phase which expired on 1 September 2016. The Group is currently in dispute with the government of The Gambia regarding the status of the A4 licence and ICSID arbitration proceedings are underway to resolve the dispute (see Section 5.7 "Legal and arbitration proceedings").

5.6 Research and development, patents and licences

The Group has had no material expenses related to research and development for the period covered by the last two financial years and up to the date of this Information Memorandum.

Other than the licences described in Section 5.4 "The business of the Group", the Group is not dependent on any patents or licences, and does not hold any patents or licences that are critical to the business or any other significant patents.

5.7 Legal and arbitration proceedings

The Group is currently in dispute with the government of The Gambia regarding the status of the A1 and A4 licences. In October 2017, the Group's wholly-owned subsidiaries African Petroleum Gambia Limited and APCL Gambia B.V lodged RFA documents with ICSID in order to protect its interests in the A1 and A4 licences in The Gambia. The tribunal for the case was constituted on 26 March 2018 with the first session held on 27 June 2018. The Group filed its memorial on admissibility, jurisdiction and the merits of its case on 28 February 2019.

Further, the Group is currently in dispute with the government of Senegal regarding the status of the ROP and SOSP PSCs. In January 2018 the Group's wholly owned subsidiary African Petroleum Senegal Limited lodged RFA documents with ICSID in order to protect its interests in the ROP and SOSP PSCs in Senegal. The tribunal for the case was constituted on 23 January 2019 with the first session held on 19 March 2019.

Except to the extent disclosed above, neither the Company nor any other company in the Group is, nor has been, during the course of the preceding twelve months involved in any legal, governmental or arbitration proceedings which may have, or have had in the recent past, significant effects on the Company's and/or the Group's financial position or profitability, and the Company is not aware of any such proceedings which are pending or threatened.

5.8 Agreements regarding third party interests in subsidiaries

Following an agreement between Prestamex Group Inc. ("Prestamex"), African Petroleum Corporation Limited (Cayman Islands) and African Petroleum Senegal Limited dated 28 November 2011, Prestamex received 10% of the shares in African Petroleum Senegal Limited for consultancy services provided by Prestamex on an exclusive basis to African Petroleum Senegal. Prestamex has maintained its 10% ownership of African Petroleum Senegal Limited (while the remaining 90% are held by African Petroleum Corporation Limited (Cayman Islands). The agreement dated 28 November 2011 *inter alia* governs Prestamex's and African Petroleum Corporation Limited (Cayman Islands)' shareholder interests in African Petroleum Senegal Limited.

Under the agreement and in consideration for the services performed by Prestamex, African Petroleum Corporation Limited (Cayman Islands), in addition to transferring 10% of its shares in African Petroleum Senegal Limited, has paid Prestamex USD 2,000,000. There are no further liabilities on the part of the Group towards Prestamex under the agreement, save for the shareholder regulations described below.

The agreement governs *inter alia* board composition, shareholder reserved matters, restrictions on the transfer of shares, pre-emption rights and deadlock resolution in African Petroleum Senegal Limited:

- **Board composition:** the agreement allows African Petroleum Corporation Limited (Cayman Islands) to appoint four directors (including the chairman) to the board of directors African Petroleum Senegal Limited. Prestamex is entitled to appoint one director for so long as it holds 10% of the issued share capital of African Petroleum Senegal Limited.

- **Shareholder reserved matters:** The written consent of shareholders holding at least 91% of issued shares is required for certain shareholder reserved matters, which in effect gives Prestamex a veto right in respect of such matters.

- **Restrictions on the transfer of shares:** Other than permitted transfers, transfers of shares (or other dealings in shares) by any shareholder are not permitted without prior written consent of all other shareholders of African Petroleum Senegal Limited. Prestamex has also undertaken not to undergo a change of control without the prior written consent from African Petroleum Corporation Limited (Cayman Islands).

- **Deadlock:** If a deadlock arises because the parties fail to agree on any of the shareholder reserved matters (as described above) or any other management matter then the issue must be referred to the respective Chairman of each shareholder and the parties shall seek to resolve the disagreement in the best interests of African Petroleum Senegal Limited.

5.9 Guarantees

As of the date of this Information Memorandum, the Group does not have any guarantees in place.

5.10 Recent development and trend information

The Group is an exploration focused oil and gas company with operations offshore West Africa. The Group's operations consist of continuous geological and geophysical research and evaluation of its licences, leading to periods of exploration and appraisal offshore drilling activities.

The Group has not experienced any changes or trends outside the ordinary course of business that are significant to the Group between 30 June 2018 and the date of this Information Memorandum, other than those described elsewhere in this Information Memorandum. The Company is not aware of any known trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the issuer's prospects for at least the current financial year. See Section 5 "Presentation of African Petroleum" and Section 7 "Industry overview" for more information about significant recent trends in the Group's business and relevant markets.

5.11 Environmental requirements

The Company's business is subject to a number of environmental requirements, in addition to such requirements imposed on the Company under the PSCs. Any non-compliance with environmental protection legislation may lead to breach of contracts and fines imposed by the competent authorities of the country of operations.

Currently, to the extent known to the Company, there are no environmental requirements preventing the Group from operating under its current Licences.

5.12 Board of Directors, Management and employees

5.12.1 Board of Directors

The Company's Constitution provides that the Board of Directors shall have no fewer than three Directors and no more than twelve Directors. The Directors are elected by the shareholders' general meeting 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. As the Company is incorporated in Australia, the Australian Corporations Act requires the Company to have at least two Directors that reside in Australia.

The Company's current Board of Directors is composed of five directors, whereof three Directors are independent of the management and main business associates.

The table below sets forth the names and positions, current term of office and shareholding, followed by additional biographical information, of the Directors as at the date of this Information Memorandum.

Name	Position	Served since	Shares	Options[3]
Dr. David King	Chairman	1 July 2013	30,000	1,000,000
Mr. Jens Pace[1]	Director	18 November 2015	1,498,938	4,550,000
Mr. Stephen West[2]	Director	18 November 2015	1,377,544	4,570,000
Mr. Bjarne Moe	Director	16 June 2014	10,000	650,000
Mr. Timothy Turner	Director	30 June 2010	4,167	400,000

1 Mr. Pace is the CEO of the Company and is accordingly a non-independent director.

2 Mr. West is the CFO of the Company and is accordingly a non-independent director.

3 These options will be cancelled and replaced with the new APCL Performance Warrants in connection with the Transaction.

All the Directors have business address at 48 Dover Street, London W1S 4FF, United Kingdom in relation to their directorships with the Company.

Dr. David King, Independent Chairman

Dr. King is a professional geoscientist and has over 30 years' experience in oil and gas and other natural resources industries. He has co-founded, as well as held executive and non-executive board positions with, a number of successful ASX listed oil and gas exploration companies, including Eastern Star Gas Limited, Gas2Grid Limited and Sapex Limited. Dr. King is currently non-executive Chairman of ASX-listed biotechnology research and development company Cellmid Ltd and non-executive director of oil and gas companies Galilee Energy Ltd and Tapoil Ltd. He is also a non-executive director (formerly Chairman) of AIM-listed (formerly ASX-listed) Litigation Capital Management Ltd. In a long corporate career, he has also served as Managing Director of ASX listed gold producer North Flinders Mines, and Chief Executive Officer of oil & gas producers Beach Petroleum and Claremont Petroleum. He was more recently Chairman of ASX listed Robust Resources Limited, Chairman of AIM listed Tengri Resources, and non-executive director of ASX listed Republic Gold Limited.

Dr. King graduated from the University of East Anglia with a BSc (Hons) in Class 1 Physics/Mathematics, holds a MSc and D.I.C. in Geophysics from the Imperial College, University of London and a PhD in Seismology from the Australian National University. From 1974-76, Dr. King was a Research Fellow with the Royal Norwegian Council for Scientific and Industrial Research (NTNF), working on the NORSAR seismic array. Dr. King is a Fellow of the Australian Institute of Company Directors, a Fellow of the Australasian Institute of Mining & Metallurgy, a Fellow of the Australian Institute of Geoscientists, a member (and past President) of the Australian Society of Exploration Geophysicists, an active member of the Society of Exploration Geophysicists and a member of the Petroleum Exploration Society of Australia. Dr. King is an Australian citizen and resides in Australia.

Mr. Jens Pace, Chief Executive Officer and Executive Director

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

Mr. Pace graduated from the University College of Swansea, University of Wales with a BSc in Geology and Oceanography. Mr. Pace graduated from the Imperial College of Science and Technology, University of London with an MSc in Geophysics. Mr. Pace is a British citizen and resides in the United Kingdom.

Mr. Stephen West, Chief Financial Officer and Executive Director

Mr. West is a qualified Fellow Chartered Accountant (Australia & New Zealand) and a Chartered Accountant (England & Wales) who holds a Bachelor of Commerce (Accounting and Business Law) from Curtin University of Technology in Australia. 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. Mr. West is currently a non-executive Chairman of ASX listed Zeta Petroleum plc. Mr. West is an Australian and British citizen and resides in the United Kingdom.

Mr. Bjarne Moe, Independent Non-Executive Director

Mr. Moe holds his degree in economics from the University of Oslo and has worked in the oil and gas sector for more than 35 years. He started out in the Ministry of Industry and was transferred to the Ministry of Petroleum and Energy when it was established in 1978. In 1988, Mr. Moe was appointed Director General and head of the Oil and Gas department. Furthermore, Mr. Moe has been a diplomat working for the Ministry of Foreign Affairs and been counsellor at the Norwegian embassy in Washington, D.C. and Mr. Moe has further chaired several international commissions for solving questions regarding median line fields, and international gas and oil pipelines. He has also been heading delegations outside of Norway to solve specific questions and been a mediator for unitization of fields etc. Mr. Moe has headed several delegations for OECD (IEA) and has been a member of the Petroleum Price board for 15 years. Mr. Moe is currently chairman of Consultor Energy AS, an energy advisory company. Mr Moe is a Norwegian citizen and resides in Norway.

Mr. Timothy Turner, Non-Executive Director

Mr. Turner is a senior and founding partner of the Australian accounting firm, HTG Partners. Mr. Turner specialises in domestic business structuring, corporate and trust tax planning and the issuing of audit opinions. 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. Mr. Turner is a Non-Executive Director of ASX listed entities Cape Lambert Resources Limited and a Non-Executive Director of

NSX listed International Petroleum Limited. Mr. Turner is a Registered Company Auditor, a registered Tax Agent and SMSF Auditor, a Fellow of CPA Australia and a Fellow of the Taxation Institute of Australia. He holds a Bachelor of Business Degree with a Major in Accounting. Mr. Turner is an Australian citizen and resides in Australia.

5.12.2 Management

The Company's Management is responsible for the daily management and the operations of the Company. The Management consists of the Chief Executive Officer, the Chief Financial Officer, the Exploration Director and the Group Financial Controller and is presented below.

The table below sets forth the names, positions, shareholding and options held, followed by additional biographical information, of the members of the Management as at the date of this Information Memorandum.

Name	Position	Employed with the Group since	Shares	Options[1]
Mr. Jens Pace	Chief Executive Officer	1 Oct 2012	1,498,938	4,550,000
Mr. Stephen West[2]	Chief Financial Officer	1 Oct 2013	1,377,544	4,570,000
Mr. Michael Barrett	Exploration Director	5 Sept 2011	1,151,667	2,940,000
Mr. Chris Butler	Group Financial Controller	19 Mar 2010	234,296	820,000

1 The options granted to the members of the management are subject to each individual's contract of service or employment.

2 Pursuant to the service agreement entered into between the Group and Mr. Pace, Mr. Pace shall receive 50,000 Shares, upon the Company securing a commercial discovery of hydrocarbons. This milestone has not yet occurred.

All of the members of the Management have their business address at 48 Dover Street, London W1S 4FF, United Kingdom.

Mr. Jens Pace, Chief Executive Officer

See Section 5.12.1 "Board of Directors" for information about Mr. Jens Pace.

Mr. Stephen West, Chief Financial Officer

See Section 5.12.1 "Board of Directors" for information about Mr. Stephen West.

Mr. Michael Barrett, Exploration Director

Mr. Barrett has over 20 years global exploration experience from his career at Chevron Corporation, and more recently at Addax/Sinopec International. Mr. Barrett has held senior positions at Chevron and Addax Petroleum, gaining substantial exploration and operations experience in Africa, namely: Angola, Cameroon, Gabon, Kurdistan and Nigeria, having also extended experience in Australia. Mr. Barrett has held a variety of technical roles covering exploration and new ventures, and was part of Chevron's global Exploration Review Team, specialising in Play and Prospect risk assessment, volumetric analysis, commercial evaluation and portfolio management. Mr. Barrett also brings added strength to the team with his background in quantitative geophysics, stratigraphic interpretation workflows and 3D visualisation. Mr. Barrett has a BSc in Geology & Geophysics from Durham University and a MSc in Petroleum Geology & Geophysics from Imperial College, Royal School of Mines. He is a British citizen and resides in the United Kingdom.

Mr. Chris Butler, Group Financial Controller

Mr. Butler has over 15 years financial experience with 8 years public practice experience gained at Bright Grahame Murray where he held the position of Audit Manager. Since joining African Petroleum in 2010, Mr. Butler has been responsible for all financial reporting obligations under the relevant stock exchange listings and petroleum cost reporting for the exploration licences held by the Group. This work includes the repeated evaluation of internal controls and implementing changes as required for a rapidly expanding company. Mr Butler graduated from Warwick University with a BSc degree in Physics and is a qualified Chartered Accountant. He is a British citizen and resides in the United Kingdom.

5.12.3 Benefits upon termination

None of the Directors' service agreements with the Group provides for benefits upon termination of employment. Whereas the same applies in respect of members of the Management, they are, however, entitled to salary in relation to notice periods of three or six months.

5.12.4 Employees

As at the date of the Information Memorandum, the Group has nine employees, whereof five are employed in the United Kingdom and four are employed in West Africa.

5.13 Corporate governance

The Board of Directors of the Company is responsible for establishing the corporate governance framework of the Company having regard to the Australian Corporations Act 2001. The Board of Directors of African Petroleum is committed to administering its corporate governance policies and procedures with openness and integrity, pursuing the true spirit of corporate governance commensurate with African Petroleum's needs. Given its previous listing on the National Stock Exchange of Australia (the "NSX"), the Company's corporate governance framework has been constructed in recognition of, and with regard to, the Australian Corporations Act; the ASX Corporate Governance Council's ("CGC") 'Corporate Governance Principles and Recommendations (the Third Edition)' (Recommendations) and CGC published guidelines; and an extensive range of varying legal, regulatory and governance requirements applicable to publicly listed companies in Australia.

The Board of Directors supports the principles of effective corporate governance and is committed to adopting high standards of performance and accountability, commensurate with the size of the Company and its available resources. Accordingly, the Board of Directors has adopted corporate governance principles and practices designed to promote responsible management and conduct of the Company's business.

The current corporate governance plan adopted by the Company is available on the Company's website www. africanpetroleum.com.au. The Company is in compliance with the NSX Corporate Governance Principles.

Following completion of the Transaction, the new Board of Directors will review the Company's corporate governance principles and assess if any amendments should be made.

5.14 Major shareholders

As at 27 March 2019, the Company had 3,407 shareholders. The table below shows the 20 largest shareholders in the Company, including those registered in the VPS, as at 27 March 2019.

#	Shareholders	Number of Shares	Percent
1	Nordnet Bank AB	14,684,291	9.45%
2	Avanza Bank AB	8,059,252	5.18%
3	Nordnet Livsforsikring AS	6,937,727	4.46%
4	Telinet Energi AS	5,602,461	3.60%
5	Danske Bank A/S	3,470,945	2.23%
6	Gekko AS	2,791,789	1.80%
7	Nordea Bank Abp	2,311,235	1.49%
8	Citibank, N.A.	2,282,310	1.47%
9	UBS Switzerland AG	2,273,305	1.46%
10	Ole Andreas Baksaas	2,191,709	1.41%
11	Swedbank AB	2,114,424	1.36%

#	Shareholders	Number of Shares	Percent
12	Six Sis AG	1,714,575	1.10%
13	Minh Hoang Pham	1,590,000	1.02%
14	Jens Pace	1,498,938	0.96%
15	Netfonds Livsforsikring AS	1,448,024	0.93%
16	Cresthaven Investments pty Ltd	1,377,544	0.89%
17	Steinar Grønland	1,353,000	0.87%
18	Michael Barrett	1,151,667	0.74%
19	John Andreas Rognstad	1,150,000	0.74%
20	Clearstream Banking S.A.	1,095,904	0.70%
		65,099,100	
	Others	90,367,346	58.13%
	Total	**155,466,446**	**100.00%**

There are no differences in voting rights between the shareholders.

Shareholders owning 5% or more of the Shares have an interest in the Company's share capital which is notifiable pursuant to the Norwegian Securities Trading Act. As at 27 March 2019, Nordnet Bank AB (9.45%) and Avanza Bank AB (5.18%) owned more than 5% of the Shares. The Company is not aware of any other persons or entities, who, directly or indirectly, have an interest of 5% of more of the Shares as at the date of this Information Memorandum.

5.15 Description of the Shares and share capital

As of the date of this Information Memorandum, the Company has 155,466,446 issued Shares fully paid in accordance with Australian law. The Shares do not have a par value. Generally, all Shares are freely transferable, subject to the registration of the transfer not resulting in a contravention of a failure to observe the provisions of a law of Australia and the transfer not being in breach of the Australian Corporations Act or applicable listing rules. All of the Shares are issued in accordance with the laws of Australia with ISIN number AU000000AOQ0. At the date of this Information Memorandum all of the Company's Shares are registered with the Company's share register in Australia, of which the beneficial rights to 152,488,276 Shares are registered in the VPS. The beneficial rights to the Consideration Shares will be registered in the VPS. The Company is listed on Oslo Axess under the ticker code "APCL".

The Company's share register is comprised of the Issuer Sponsored Sub-register where Shares can be transferred off-market.

The Company only has one class of Shares on issue. The Shares are equal in all respects and each Share carries one vote at the Company' general meeting. The Company does not hold any treasury shares.

The table below sets forth the historical development of the Company's share capital and the number of issued and outstanding Shares since 1 January 2015 and until the date of this Information Memorandum.

Date	Type of change in share capital	Change in number of Shares	Issue price per Share (NOK)	Total number of issued Shares following change
Mar 2015	Private placement	271,732,000	0.35	957,589,922
Apr 2015	Retail offering	11,604,330	0.35	969.194.252
Oct 2015	Share consolidation 10:1	(872,274,408)	-	96,919,844
Oct 2015	Private placement	9,691,937	1.70	106,611,781
May 2016	Exercise of options	73,333	1.70	106,685,114
Jan 2017	Exercise of options	33,333	1.70	106,718,447
Jan 2017	Private placement	10,670,000	2.50	117,388,447
Mar 2017	Exercise of options	10,900	7.50	117,399,347
Mar 2017	Issue of shares in settlement of outstanding fees	164,857	3.02	117,564,204
April 2017	Exercise of options	333,333	4.00	117,897,537
April 2017	Exercise of options	26,667	4.00	117,924,204
May 2017	Private placement	33,250,000	7.75	151,174,204
May 2017	Exercise of options	33,334	1.70	151,207,538
Oct 2017	Issue of shares in settlement of salary	137,892	1.48	151,345,430
Dec 2017	Issue of shares in settlement of salary	4,121,016	0.91	155,466,446

6 AFRICAN PETROLEUM SELECTED FINANCIAL INFORMATION

6.1 Historical financial information and summary of accounting policies

The Company's historical consolidated financial statements have been prepared in accordance with International Financial Reporting Standard ("IFRS").

The Company's audited consolidated financial statements as at, and for the years ended, 31 December 2017, 2016 and 2015, including an overview of the Company's accounting policies, explanatory notes and auditor's statements, are incorporated by reference hereto, see Section 11.2 "Incorporation by reference" below. The Company's unaudited consolidated financial statements as at, and for the six month periods ended, 30 June 2018 and 2017, are incorporated by reference hereto, see Section 11.2 "Incorporation by reference" below.

The Company's independent auditor is BDO Audit (WA) Pty Ltd ("BDO"), a member firm of BDO International Ltd, 38 Station Street, Subiaco, Western Australia 6008. BDO is a Chartered Firm with the Institute of Chartered Accountants Australia. BDO has audited the Company's consolidated financial statements as at, and for the years ended, 31 December 2017 and 2016, without qualifications or disclaimers. Ernst & Young, 11 Mounts Bay Road, Perth Western Australia 6000, audited the Company's consolidated financial statements for the year ended 31 December 2015. BDO has issued an Independent Practitioner's Assurance Report on the process to compile the pro forma financial information included in this Information Memorandum set out in Appendix C. BDO has not audited or reviewed or produced any report on other information provided in this Information Memorandum.

6.2 Significant change since 30 June 2018

Other that the Transaction described in Section 4 "Description of the Transaction", there has not been any significant change to the Group's financial and/or trading position since 30 June 2018 and to the date of this Information Memorandum.

6.3 Consolidated historical financial information

The following tables present selected financial information for the Company that has been derived from the Company's unaudited consolidated financial statements as at, and for the six month periods ended, 30 June 2018 and 2017, and the Company's audited consolidated financial statements as at, and for the years ended, 31 December 2017, 2016 and 2015.

6.3.1 African Petroleum consolidated statement of income

In USD$	**Period ended 30 June**		**Year ended 31 December**		
	2018 *(unaudited)*	**2017** *(unaudited)*	**2017** *(audited)*	**2016** *(audited)*	**2015** *(audited)*
Continuing operations					
Revenue	7	62,108	228,692	210,461	454,975
Exploration & evaluation expenditure	(457,165)	(9,457,218)	(9,856,447)	9,943,287	(6,837,484)
Impairment of exploration and evaluation expenditure	-	-	(18,367,865)	(8,949,626)	(13,698,154)
Consulting expenses	(1,188,384)	(586,636)	(1,423,965)	(860,541)	(2,853,020)
Compliance and regulatory expenses	(100,795)	(144,926)	(242,759)	(162,877)	(371,500)
Administration expenses	(234,635)	(265,784)	(572,101)	(724,561)	(1,300,467)
Employee benefits	(1,527,878)	(970,876)	(4,387,472)	(2,505,712)	(4,571,413)
Travel expenses	(48,420)	(228,018)	(476,776)	(260,293)	(575,338)
Impairment of consumable spares	-	-	-	-	(1,497,111)

In USD$	Period ended 30 June		Year ended 31 December		
	2018 *(unaudited)*	**2017** *(unaudited)*	**2017** *(audited)*	**2016** *(audited)*	**2015** *(audited)*
Loss from disposal of freehold land	-	-	-	-	(856,158)
Aircraft expenses	-	-	-	(9,328)	(444,094)
Impairment of aircraft	-	-	-	-	(429,110)
Depreciation & amortisation expense	(1,227)	(1,785)	(3,387)	(4,272)	(455,629)
Impairment of related party loans	-	-	-	-	(62,648)
Net unrealised gains on fair value of financial liabilities	-	77,645	77,645	414,927	2,561,298
Foreign exchange gain / (loss)	(30,680)	(77,736)	4,883	298,537	(294,243)
Loss from continuing operations before income tax	**(3,589,177)**	**(11,593,226)**	**(35,019,552)**	**(2,609,998)**	**(31,230,096)**
Income tax expense	-	-	-	(7,618)	-
Loss from continuing operations	**(3,589,177)**	**(11,593,226)**	**(35,019,552)**	**(2,617,616)**	**(31,230,096)**
Other comprehensive gains					
Foreign exchange (loss) / gain on translation of functional currency to presentation currency	2,405	(24,540)	(33,930)	(216,466)	108,171
Total comprehensive loss for the year	**(3,586,772)**	**11,617,766**	**(35,053,482)**	**(2,834,082)**	**(31,121,925)**
Loss attributable to:					
Non-controlling interest	(19,982)	(8,058)	(399,488)	(56,660)	(123,243)
Owners of the parent	(3,569,195)	(11,585,168)	(34,620,064)	(2,560,956)	(31,106,853)
Comprehensive loss attributable to:					
Non-controlling interest	(19,982)	(8,058)	(399,488)	(56,660)	(123,243)
Owners of the parent	(3,5666,789)	(11,609,708)	(34,653,995)	(2,777,422)	(30,998,682)
Loss per share to members					
Basic and diluted loss per share (US cents)	**(2.37)**	**(9.13)**	**(24.86)**	**(2.40)**	**(31.81)**

6.3.2 African Petroleum consolidated statements of financial position

In USD$	As at 30 June		As at 31 December		
	2018 *(unaudited)*	**2017** *(unaudited)*	**2017** *(audited)*	**2016** *(audited)*	**2015** *(audited)*
Assets					
Current assets					
Cash and cash equivalents	9,423,048	16,129,109	13,186,482	233,298	607,512
Trade and other receivables	106,736	151,014	113,844	199,223	187,756
Restricted cash	902,937	1,996,687	902,937	4,944,093	12,569,093
Prepayments	176,175	171,321	125,748	120,403	157,027
Non-current asset held for sale	-		-	-	501,925
Total current assets	10,608,897	18,448,131	14,329,011	5,497,017	14,023,313
Non current assets					
Inventories	1,006,908	1,006,908	1,006,908	1,006,908	1,006,908

In USD$	As at 30 June		As at 31 December		
	2018 *(unaudited)*	**2017** *(unaudited)*	**2017** *(audited)*	**2016** *(audited)*	**2015** *(audited)*
Property, plant and equipment	2,516	3,667	3,743	4,104	9,753
Exploration and evaluation expenditure	9,406,536	28,395,022	9,107,859	27,582,689	37,583,467
Total non current assets	10,415,960	29,405,597	10,118,510	28,593,701	38,600,128
Total assets	**21,024,857**	**47,853,728**	**24,447,521**	**34,090,718**	**52,623,441**
Liabilities					
Current liabilities					
Trade and other payables	12,867,865	15,330,592	13,288,671	21,691,260	24,118,636
Provisions	-	-	-	-	13,586,770
Derivative financial liabilities	-	-	-	75,218	447,438
Total current liabilities	12,867,865	15,330,592	13,288,671	21,766,478	38,152,844
Total liabilities	**12,867,865**	**15,330,592**	**13,288,671**	**21,766,478**	**38,152,844**
Net assets	**8,156,992**	**32,523,134**	**11,158,850**	**12,324,240**	**14,470,597**
Equity					
Issued capital	643,438,272	642,964,344	643,438,272	611,455,218	611,439,967
Reserves	21,840,267	19,664,835	21,252,947	19,381,839	18,925,831
Accumulated losses	(653,655,877)	(627,051,785)	(650,086,682)	(615,466,618)	(612,905,662)
Parent interests	11,622,662	35,577,394	14,604,537	15,370,439	17,460,138
Non-controlling interests	(3,465,670)	(3,054,258)	(3,445,687)	(3,046,199)	(2,989,539)
Total equity	**8,156,992**	**32,523,136**	**11,158,850**	**12,324,240**	**14,470,597**

6.3.3 African Petroleum consolidated statement of cash flows

In USD$	Period ended 30 June		Year ended 31 December		
	2018 *(unaudited)*	**2017** *(unaudited)*	**2017** *(audited)*	**2016** *(audited)*	**2015** *(audited)*
Cash flows from operating activities					
Payments to suppliers and employees	(3,426,696)	(17,756,424)	(22,200,485)	(3,288,233)	(11,053,979)
Interest received	7	3	9	6,885	49,695
Finance costs	(9,794)	(10,084)	(29,322)	(37,089)	(167,561)
Other income	-	172,589	197,804	172,589	72,922
Net cash flows used in operating activities	**(3,436,483)**	**(17,593,916)**	**(22,031,994)**	**(3,145,848)**	**(11,098,923)**
Cash flows from investing activities					
Proceeds from sale of plant and equipment	-	8,000	30,879	2,500	57,000
Payment for plant and equipment	-	(1,348)	(3,026)	(4,337)	(2,252)

In USD$	Period ended 30 June		Year ended 31 December		
	2018 *(unaudited)*	**2017** *(unaudited)*	**2017** *(audited)*	**2016** *(audited)*	**2015** *(audited)*
Proceeds from disposal of freehold land	-		-	-	200,000
Payment for exploration and evaluation activities	(298,677)	(812,333)	(1,037,835)	(5,288,328)	(5,731,049)
Proceeds from farm out of exploration and evaluation assets	-	-	-	6,339,480	-
Cash backing security returned	-	3,281,250	4,375,000	6,000,000	616,017
Cash backing security provided	-	(333,844)	(333,844)	(4,375,000)	(1,115,850)
Net cash from investing activities	**(298,677)**	**2,141,725**	**3,031,174**	**2,674,315**	**(5,976,134)**
Cash flows from financing activities					
Proceeds from issue of shares	-	33,111,647	33,644,423	-	14,067,499
Capital raising costs	-	(1,852,606)	(1,852,606)	-	(210,430)
Proceeds from exercise of share options	-	191,238	191,238	15,251	-
Net cash from financing activities	**-**	**31,450,278**	**31,983,055**	**15,251**	**13,857,069**
Net increase/(decrease) in cash and cash equivalents	**(3,735,160)**	**15,998,088**	**12,982,235**	**(456,282)**	**(3,217,988)**
Cash and cash equivalents at the beginning of the period	13,186,482	233,298	233,298	607,512	3,869,086
Net foreign exchange differences	(28,274)	(102,278)	(29,051)	82,068	(43,586)
Cash and cash equivalents at the end of period	**9,423,048**	**16,129,108**	**13,186,482**	**233,298**	**607,512**

6.3.4 African Petroleum consolidated statement of changes in equity

In USD$	Period ended 30 June		Year ended 31 December		
	2018 *(unaudited)*	**2017** *(unaudited)*	**2017** *(audited)*	**2016** *(audited)*	**2015** *(audited)*
Balance at 1 January	**11,158,850**	**12,324,240**	**12,324,240**	**14,470,597**	**33,429,015**
Loss for period	(3,589,178)	(11,593,226)	(35,019,552)	(2,617,616)	(31,230,096)
Foreign currency exchange differences on translation from functional currency	2,405	(24,540)	(33,930)	(216,466)	108,171
Total comprehensive loss for period	(3,586,773)	(11,617,766)	(35,053,482)	(2,834,082)	(31,121,925)
Issue of capital	-	31,317,887	31,791,816	-	10,848,156
Exercise of options	-	191,238	191,238	15,251	-
Share-based payments	584,915	307,537	1,905,038	672,474	1,315,351
Balance at period end	**8,156,992**	**32,523,136**	**11,158,850**	**12,324,240**	**14,470,597**

6.3.5 Key financial information by segment

The Group operates only one segment, which is exploration for hydrocarbons.

For management purposes, the Group is organised into one main operating segment, which involves exploration for hydrocarbons. All of the Group's activities are interrelated, and discrete financial information is reported to the Board of Directors and the executive management team (Chief Operating Decision Makers) 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 analysis of the location of non-current assets is as follows:

In USD$	**Period ended 30 June**		**Year ended 31 December**		
	2018 *(unaudited)*	**2017** *(unaudited)*	**2017** *(audited)*	**2016** *(audited)*	**2015** *(audited)*
Côte d'Ivoire	-	8,550,375	-	8,225,750	14,001,617
Gambia	-	6,380,591	-	6,380,591	3,544,384
Liberia	-	-			8,308,792
Senegal	-	4,082,074	-	3,900,274	3,200,362
Sierra Leone	9,406,536	9,382,357	9,107,859	9,076,824	8,529,929
United Kingdom	1,009,424	1,010,200	1,010,651	1,010,262	1,015,044
	10,415,960	**29,405,597**	**10,118,510**	**28,593,701**	**38,600,128**

6.4 Liquidity and capital resources

For the period covered by the historical financial information and up to the date of this Information Memorandum, the Company has completed one equity placement in October 2015 raising NOK 16.5 million (approximately USD 2 million), one equity placement in January 2017 raising NOK 26.7 million (approximately USD 3.1 million) and one equity placement in May 2017 raising NOK 258 million (approximately USD 30 million).

As at 30 June 2018, the Company had available liquid funds in the form of cash and cash equivalents amounting to USD 9,423,048. The Group does not have any financial debt at the date of this Information Memorandum.

6.4.1 Restrictions on use of capital

As at the date of this Information Memorandum, the Group does not have any interest bearing debt that restricts or has restricted the use of capital and that have materially affected, or could materially affect, directly or indirectly, the Group's operations.

6.4.2 Working capital statement

The Company is of the opinion that the working capital available to the Group is sufficient for the Group's present requirements, for the period covering at least 12 months from the date of this Information Memorandum.

7 INDUSTRY OVERVIEW

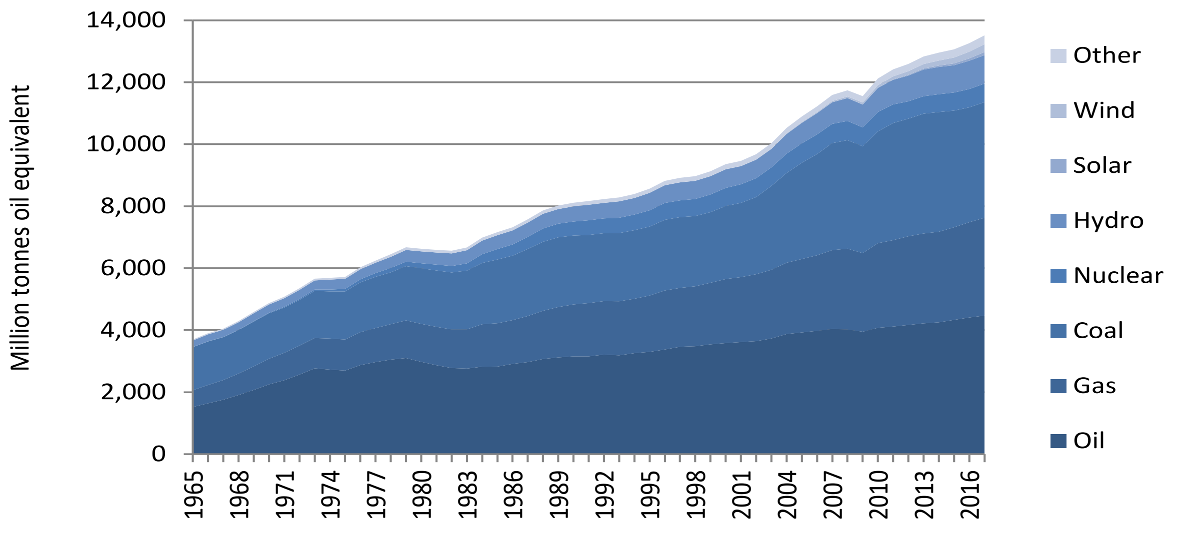
The Group is an upstream oil and gas business focused on the exploration, development and production phases of the upstream value chain. The Group's business is to gain and de-risk oil and gas licences in the West African region and successfully explore for oil and gas in its licences. In the event of a commercial discovery the Group will participate in maturing its discoveries towards development and eventually commercial hydrocarbon production. While the Group has internal resources to conduct geological and geophysical work, as well as drilling operations, to conduct its business, the Group is reliant on third party providers of (when relevant) seismic data, offshore vessel and drilling rig services, as well as engineering and other consultancy services. The long-term profitability of the Group is highly dependent on its success in discovering oil and gas, as well as the long-term development of hydrocarbon commodity prices. As such this chapter provides certain background information on the dynamics in the pricing of oil and gas, as well as the historic pricing of oil.

7.1 The global energy markets

World energy consumption has steadily increased since the industrial revolution, a trend which is expected to continue in the medium term. Fossil fuels continue to supply more than 85 per cent of the world's energy. Oil is the largest energy source, meeting 34 per cent of the world's energy consumption, while natural gas accounts for 23 per cent and coal for 28 per cent.[2]

The world consumption of primary energy, including oil, natural gas, coal, nuclear, hydro power and other renewable energy, increased by 1.9 per cent in 2017. Global oil consumption increased by 1.9 million barrels per day or 1.8 per cent in 2017.

Figure 7.1: Global Energy Consumption (Mtoe)



Source: BP Statistical Review of World Energy June 2018.

7.2 The oil and gas market in Africa

Resources generally, and oil and gas specifically, have played an important role in Africa's economic growth. African countries continue to increase their production of oil and/or gas.

[2] BP Statistical Review of World Energy June 2018, latest publication as per the date of this Information Memorandum.

Most of the oil reserves (and production) in Africa comes from Nigeria, Angola, Algeria and Libya, which together account for more than 75 per cent of the continent's oil production and 85 per cent of its remaining proven reserves.

Over the past twelve months the Republic of Congo, Nigeria and Ghana have increased their production levels, whereas Equatorial Guinea, Sudan and Tunisia have seen their production declining.

Proved natural gas reserves in Africa are mainly concentrated in four countries – Algeria, Egypt, Libya and Nigeria – which possess 92.3 per cent of the continent's proved reserves. The continent has vast gas resources, however, due to lack of commercial contracts and development plans these are currently classified as contingent resources and have not been converted into proven (or probable) reserves. Over the next few years it is expected that a significant amount of resources in Mozambique, Senegal and Mauritania are expected to be converted into reserves.[3]

Until 2010, the biggest importer of Africa's oil production was the United States with 1.8 million barrels per day exported from sub-Saharan African countries to the United States. By 2015 the United States was only importing 274,000 barrels per day from sub-Saharan Africa due to a dramatic increase in domestic production in the United States. The decreased demand from the United States has been compensated by the increasing demand from emerging economies such as China, India and Brazil.

7.3 Overview of the global oil market

7.3.1 World oil production, consumption and reserves

Oil is a common description of hydrocarbons in liquid form. Crude oil produced from different oil fields varies greatly in composition, and the composition and distribution of hydrocarbon components determines the weight of the oil, with light crude oil having a higher percentage of light hydrocarbons than heavier oil. Light oil requires less refinement to be usable and is therefore typically more valuable than heavy oil, however pricing and quality differentials are subject to market dynamics and may change from time to time.

Oil is well-suited for storage and transportation and is transported over long distances in large crude oil tankers or pipelines. Because of this, oil is a commodity with a well-developed global market. The prices are determined on the world's leading commodities exchanges, with New York Mercantile Exchange (NYMEX) in New York and the Intercontinental Exchange (ICE) in London the most important markets for the determination of global oil prices. Relative oil price differentials are primarily determined by the weight of the oil and its sulfur content, with WTI, the main benchmark for NYMEX, as the lightest and sweetest (lowest in sulfur) of the main benchmarks in oil pricing. Brent crude, the main benchmark for ICE, is slightly heavier.

Crude oil is used for a variety of purposes, the most important being the production of energy rich fuels, with approximately 70 per cent of hydrocarbons being used for gasoline, diesel, jet fuel and other fuel oils. The remaining hydrocarbons are used as raw material for many chemical products, including pharmaceuticals, solvents, fertilizers, pesticides and plastics.

World oil consumption in 2017 was approximately 98.2 million barrels per day, of which Asia Pacific, North America and Europe including Eurasia (most importantly, Russia) accounted for approximately 35 per cent, 25 per cent and 20 per cent, respectively. Consumption in the Middle East was about 9.5 per cent of the world total consumption. In Africa oil remains the leading fuel, accounting for 34 per cent of the continent's energy consumption by 2040.[4]

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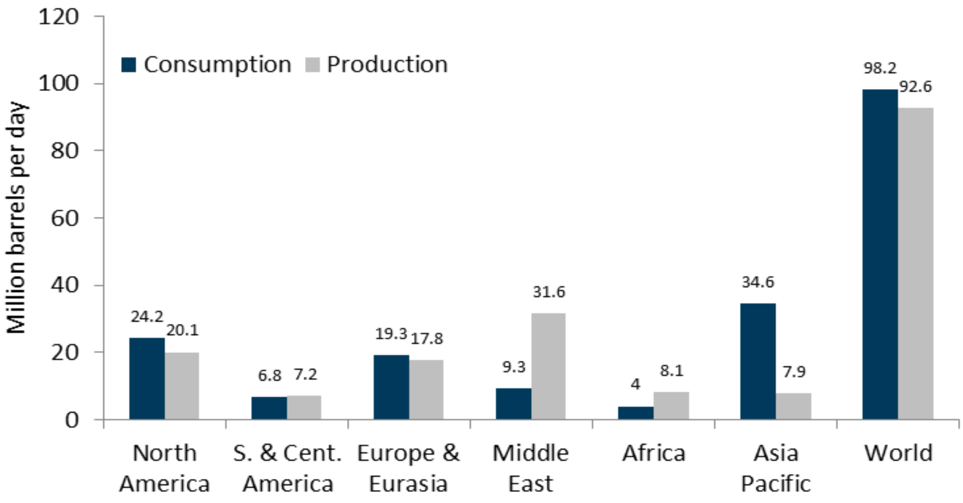
[3] Source: BP and Kosmos investor presentations.

[4] Source: BP Energy outlook -2019.

The Middle East is the world's largest oil producing region, accounting for 34 per cent of the world total. North America is second behind the Middle East, accounting for 22 per cent, followed by Europe and Eurasia with 19 per cent. Despite being the largest consuming region, oil production in Asia Pacific accounts for only 9 per cent of total world production.

Figure 7.2: Global oil consumption and production by region, 2017



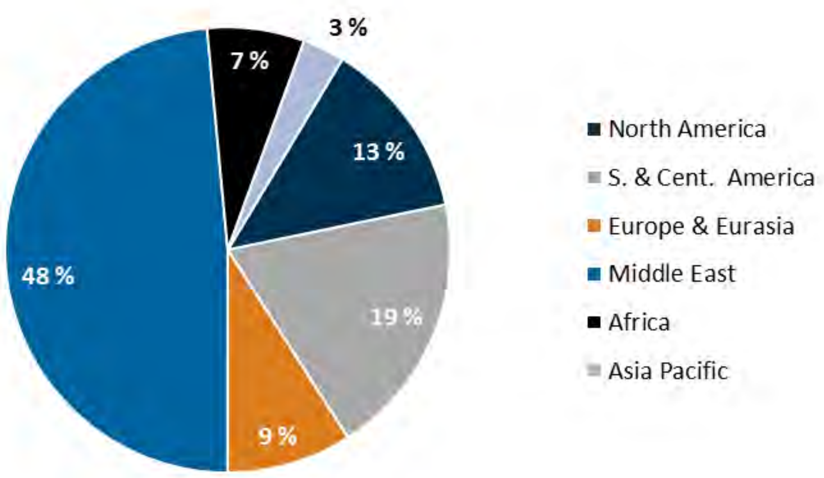
Source: Left chart: BP Statistical Review of World Energy June 2018.

Worldwide proven oil reserves stood at an estimated 1,697 billion barrels at the end of 2017, enough to meet some 50 years of global production at 2017 production levels.

The members of OPEC together held 71.8 per cent of total global reserves in 2017. OPEC includes the largest Middle East oil producers, namely Iran, Iraq, Kuwait, Saudi Arabia, Qatar and the UAE, in addition to Algeria, Angola, Congo, Equatorial Guinea, Libya, Nigeria, Gabon, Ecuador, and Venezuela. OPEC has historically played the role of swing producer in the global oil market and its decisions have had considerable influence on oil supply availability and thus international oil prices.

Chart 7.3 below shows the historical development in proven oil reserves, as well as the current composition between OPEC and main non-OPEC countries.

Figure 7.3: Distribution of proven world oil reserves, 2017



Source: BP Statistical Review of World Energy June 2018.

7.3.2 The oil price

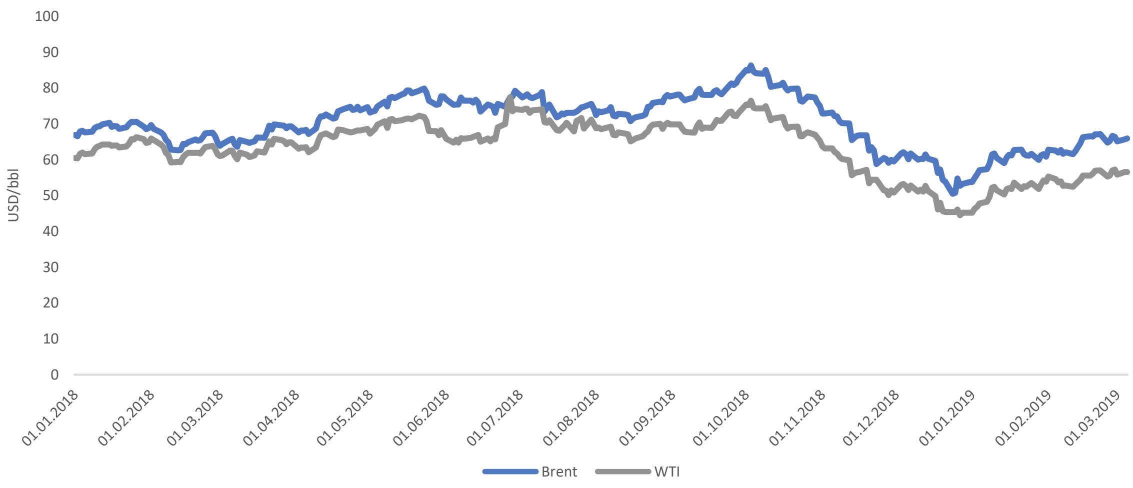
Oil prices were close to all-time highs for most of 2011, 2012, 2013 and the first half of 2014, with Brent oil trading within a USD 100-125/bbl range most of the time. However, during the second half of 2014, oil prices declined steeply and in 2015 Brent averaged USD 54/bbl. Towards the end of 2015 and into 2016, oil prices decreased further, and Brent reached a low of USD 28/bbl in January 2016. Since then, prices have recovered substantially with Brent averaging USD 55/bbl in 2017 and USD 71.5/bbl in 2018. After a decline towards the end of 2018, oil prices have recovered and Brent is currently trading at a range comprised between USD 60-65/bbl.[5] Over the past twelve months, Brent has averaged USD 70/bbl. [6]

As evidenced by the price changes in recent years, the oil price is highly dependent on the current and expected future supply and demand of oil. As such, it is influenced by global macroeconomic conditions and may experience material fluctuations based on economic indicators and material economic events as well as geopolitical events. Historically, oil prices have also been heavily influenced by organizational and national policies, most significantly the formation of OPEC and subsequent production policies announced by the organization. The figure below shows Brent oil price development from 1 January 2000 to 6 March 2019.

[5] Factset as of 6 March 2019.

[6] As above.

Figure 7.4: Development in crude oil prices (USD per barrel)



Source: Factset

7.4 Overview of the global gas market

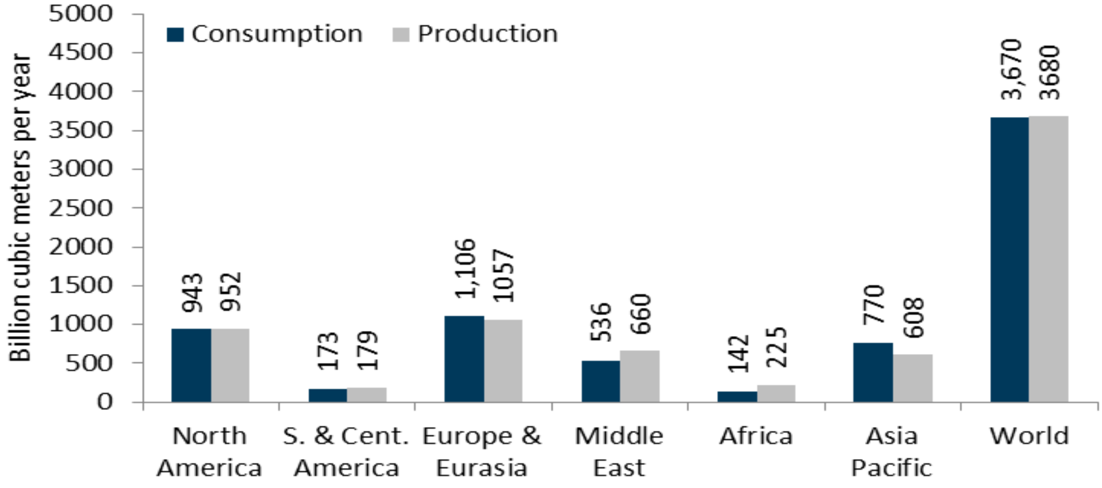
Natural gas is typically colourless, odourless and non-toxic at ambient temperatures. It can be found in onshore and offshore reservoirs, either as associated gas in crude oil or condensate or alone as non-associated gas. Natural gas is composed primarily of methane, but may also contain ethane, propane and heavier hydrocarbons. Small quantities of nitrogen, oxygen, carbon dioxide, sulphur compounds and water can also be found in natural gas. It is often termed a premium commodity for its value as both an energy source and as a feedstock for petrochemical products, and because it is relatively clean-burning. As a result, natural gas is used in a variety of ways: for home and business heating, electric power generation, the manufacture of petrochemical products ranging from plastics to fertilizers and intermediate materials, and as a vehicle fuel.

7.4.1 World gas production, consumption and reserves

In 2017, total world consumption of gas was approximately 3,670 billion cubic meters ("bcm") of which Europe and Eurasia, North America and Asia Pacific accounted for approximately 30 per cent, 26 per cent and 21 per cent, respectively. Consumption of gas in the Middle East was approximately 536 bcm in 2017, representing approximately 15 per cent of the world total. Production in the Middle East exceeded consumption by 123 bcm. Africa will become an increasingly important producer of natural gas, with production expected to increase by 245 bcm to 470 bcm in 2040[7]

[7] Source: BP Energy outlook -2019.

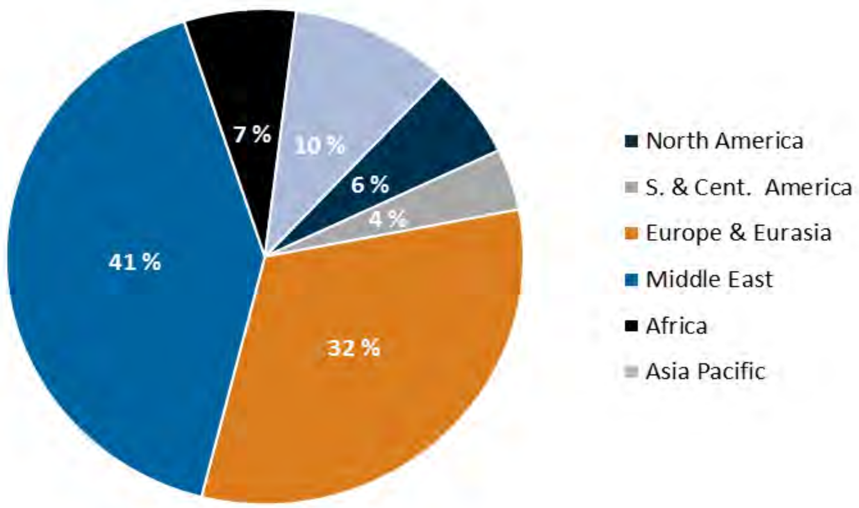
Figure 7.5: Global gas consumption and production by region, 2017



Source: Left chart: BP Statistical Review of World Energy June 2018.

Total world proven gas reserves stood at approximately 193 trillion cubic meters at the end of 2017. These reserves are enough to meet approximately 53 years of global gas production at 2017 levels. Approximately 41 per cent of total world proven gas reserves are in the Middle East, while Europe and Eurasia contain 32 per cent (of which the majority is in Russia and Turkmenistan).

Figure 7.6: Distribution of proven world gas reserves, 2017



Source: BP Statistical Review of World Energy June 2018.

7.4.2 The gas price

Because gas is not easily transported, gas prices are not determined by a world-wide market. Gas prices are usually determined regionally, with regions defined by pipeline and LNG transportation networks. There is less correlation between regional gas prices than there is between the prices of various types of oil, but there is correlation between gas prices and the oil price and other energy prices.

Gas price volatility is significantly higher than oil price volatility. This is primarily since gas is more difficult to store (and transport) than oil, meaning that gas prices are affected by immediate supply and demand within pipeline networks and other associated transporting costs.

Three broad pricing mechanisms exist for gas. The first, mostly seen in international trade and in long-term contracts, involves linking gas to either crude or petroleum product prices. The second pricing mechanism is regulated pricing in domestic markets where governments set fixed prices usually reflecting production and transportation costs. The final mechanism is competitive pricing whereby trading points, often called hubs, are established in major markets and price is determined by supply and demand at these hubs.

The gas market in the U.S. is largely deregulated. There are multiple trading points across the U.S. and Canada, but the most active point is the Henry Hub in Louisiana. In Europe, gas has historically been traded under long-term contracts with pricing linked to diesel and heavy fuel. In recent years, however, an increasing share of European gas volumes have shifted from oil based to hub-based pricing, where gas supply demand dynamics determine the price. Several trading hubs for gas have been established, the most active of which is the National Balancing Point (NBP), in the United Kingdom. Oil-linked pricing has been prevalent in Asia, where large volumes of gas have been imported in liquefied form under long-term contracts.

In Africa, gas prices are more varied and influenced by a variety of factors. Large gas developments, where liquefaction and export are envisaged, are generally priced in line with international LNG markets. Smaller gas developments, often located onshore, are instead directly correlated to the local power prices, as gas is seen as an alternative source of power generation and as such it is directly competing against other fossil fuels such as diesel and petrol. These onshore developments typically show higher gas prices than their counterparts in the US and Europe. One common feature of gas developments in Africa is the degree of inter-dependence with local infrastructure: regions with existing gas gathering facilities and pipeline networks (such as Nigeria and South Africa) offer a much more liquid market, whereas regions with less sophisticated infrastructure are more dependent on a single off-taker to determine ultimate pricing.

7.5 Competition in the oil market

The oil market is a highly competitive environment, where all competitors offer the same product: crude oil. There is little differentiation with regards to the product throughout the industry, although the product may be offered with different quality (and with correspondingly different price). The market for oil production is dominated by a few producers with a substantial share of total production and a very long list of smaller producers. Of a total production of liquids in excess of 92 million barrels per day, the top ten largest producers have a market share in excess of approximately 60 per cent.

Figure 7.7: Top Ten Largest Oil Producers

Company	Estimated Production (millions of barrels per day)	Share of Production
Saudi Aramco	12.5	14%
Gazprom	9.7	11%
National Iranian Oil Co	6.4	7%
ExxonMobil	5.3	6%
PetroChina	4.4	5%
BP	4.1	4%
Royal Dutch Shell	3.9	4%

Pemex	3.6	4%
Chevron	3.5	4%
Kuwait Petroleum Corp	3.2	3%
Total Top 10	**56.6**	**61%**

Source: Forbes Magazine

Oil and gas production in Africa is led by the major integrated companies, particularly the Italian and French majors, ENI and Total SA respectively. Italian and French investors, who have deep roots in the region, aren't the only foreign investors interested in Africa. In recent years, Africa has seen increasing interest from NOCs as well as traded companies from outside the region, notably from China, India, Malaysia and Russia.

8 PRESENTATION OF PETRONOR

This Section provides an overview of the business of PetroNor as of the date of this Information Memorandum. The following discussion contains Forward-looking Statements that reflect the Company's plans and estimates; see "Cautionary note regarding forward-looking statements" in Section 3.3. You should read this Section in conjunction with the other parts of this Information Memorandum, in particular Section 1 "Risk Factors" and Section 9 "The combined Company".

8.1 Name, incorporation and registered office

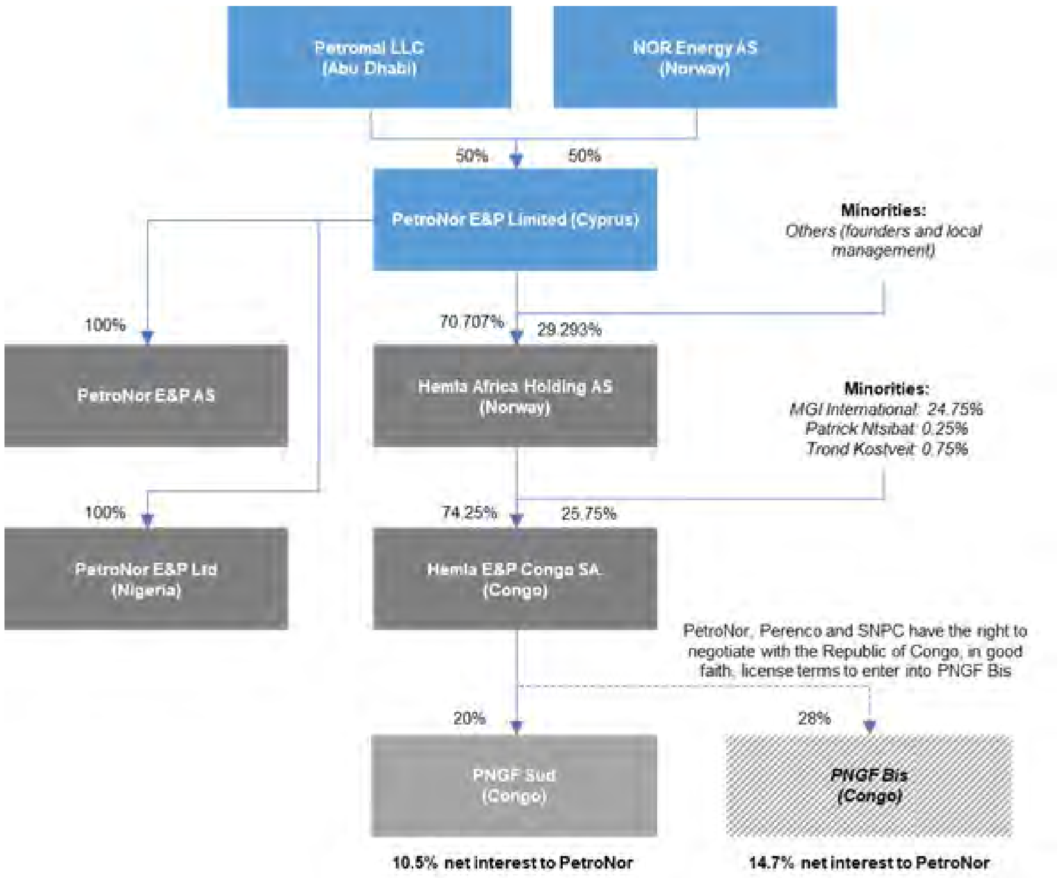
PetroNor's registered name is PetroNor E&P Ltd. PetroNor is a private company limited by shares registered in the Republic of Cyprus under registration number HE 367916. PetroNor was incorporated in Cyprus as a limited liability company on 3 April 2017 and is subject to Cypriot law. PetroNor has its registered address at Arch. Makariou III, 42E Matina Court, 3rd floor, Office 303, 1065 Nicosia, Cyprus and its telephone number is +47 22 55 46 07 and its website is www.petronorep.com.

NOR Energy AS is a Norwegian company with registration no. 989 747 444, and its registered address is Karenslyst Allé 4, N-0278 Oslo, Norway.

Petromal - Sole Proprietorship LLC is a company incorporated under the laws of U.A.E., with its registered address at M floor, Al Heel Tower, Al Khalidiya, Abu Dhabi, U.A.E.

8.2 Legal structure

NOR holds 50% of the shares and Petromal holds 50% of the shares in PetroNor, jointly constituting 100% of the issued and outstanding shares in PetroNor (the "PetroNor shares"):



[8] One (1) share in Petronor E&P Ltd (Nigeria) held by Dr. Tee Mac Omatshola Iseli as local director.

8.3 Business description

8.3.1 Introduction

PetroNor is a privately held, Africa focused E&P independent, which is owned 50% by Petromal (economic benefit interest 45.572%) and 50% by NOR (economic benefit interest 54.428%). Petromal is an Abu Dhabi based integrated oil and gas company with operations and investments in the upstream, downstream, oil field service and EPC sectors. NOR is a Norwegian upstream oil and gas E&P with its history from the North Sea and Africa. The operating organization is situated in PetroNor E&P AS. PetroNor owns its interests in PNGF Sud through controlling interests in Hemla Africa Holding AS and HEPCO.

PetroNor had an average production of 2,117 bbl/d in 2018 and had a total revenue of USD 99.5 million. Total assets amounted to USD 52.9 million at the end of 2018 based on preliminary unaudited financials.

As of 31 December 2018, PetroNor is estimated to have cash and cash equivalents of USD 6.5 million and debt of USD 10 million. The debt carries an interest rate of 1-month LIBOR +10%, has a maturity date of May 2020 and amortizes in monthly instalments.

8.3.2 Overview of PetroNor's operations

PetroNor's assets are located approximately 25km off the coast of Pointe Noire in water depths of 80-100 metres. PetroNor, through HEPCO participated in the 2016 tender process with the Congo Ministry of Petroleum for participation in the PNGF Sud licence (brown field). HEPCO was awarded a 20% working interest in the PNGF Sud licence (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.

Field details[9]

Field	Official licence name	Production start	Produced to date	Gross 2P reserves	Gross 2C resources	Gross Current production	Producing wells
		year	*mmbbl*	*mmbbl*	*mmbbl*	*bbl/d*	*#*
Asset: PNGF Sud (10.5% working interest, Perenco operator)							
Tchibouela..........	Tchibouela II	1987	318	47.9	12.0	12,500	33[10]
Tchibouela East	Tchibouela II	1998	14	TBA	TBA	To be resumed in 2019	TBA
Tchendo	Tchendo II	1991	69	19.2	10.8	4,700	16
Tchibeli...............	Tchibeli-Litanzi II	2000	27	10.9	6.7	3,000	3
Litanzi	Tchibeli-Litanzi II	2006	9	3.2	2.6	1,400	1
Asset: PNGF Bis (terms of licence under negotiation, Perenco expected to be operator)							
Loussima SW	PNGF Bis	2019			28.9		
Loussima.............	PNGF Bis	TBA			TBA		

[9] Volumes as per 1.1.2019 based on CPR prepared by AGR Petroleum Services AS dated 30 October 2018 adjusted for production through 2018.

[10] Note that the active well number may vary from month to month for all the structures.

PNGF Sud

PNGF Sud is estimated to hold net 2P reserves per 1 January 2019 of 8.5 mmbbl and 2C contingent resources of 3.4 mmbbl. The estimate is based on a CPR prepared by AGR Petroleum Services AS dated 30 October 2018 with volumes as of 1 January 2018, adjusted for actual production during 2018. The CPR is attached hereto as Appendix B. The table below sets out the licence partners in PNGF Sud.

Company	Interest
Societe Nationale des Petroles du Congo (SNPC)	15%
Perenco Congo S.A.	40%
Hemla E&P Congo S.A.	20%
Kontinent Congo S.A.	10%
Africa Oil & Gas Corporation (AOGC) S.A.	10%
Petro Congo S.A.	5%
Total	**100%**

Initially discovered in 1979, PNGF Sud commenced production in 1987 and is currently producing c. 21,600 bbl/d gross from four oil fields, Tchibouela, Tchendo, Tchibeli and Litanzi. Following the entry of the new licence group in 2017, significant operational improvements have been made, increasing gross production from c. 15,000 bbl/d in January 2017 to today's level, and reducing operating costs from some 26 USD/bbl to current level of c.11 USD/bbl. The production increase has mainly been driven by work-overs of existing wells and been achieved by minor investments of USD 30 million gross. Through further work-overs, surface and process improvements and infill drilling, gross production from PNGF Sud is expected to continue to grow in the coming years.

The PNGF Sud fields are developed with seven wellhead platforms and currently produce from more than 50 active production wells, with oil exported via the onshore Djeno terminal (Tchibouela, Tchendo and Tchibeli) and the Nkossa FPSO (Litanzi). With its long production history, substantial well count and extensive infrastructure, PNGF Sud offers well diversified and low risk production and reserves with low break-even cost.

Tchibouela Field

Tchibouela Main consists of three disconnected reservoirs: Senonian, Turonian and Cenomanian with reservoir depths ranging from 300 to 1000 mTVDSS. The structure is a dome formed anticline and the reservoir quality is good but varying. The main reservoirs in Turonian and Cenomanian contain oil of 27 deg API with low GOR. The youngest reservoir, Senonian, contains gas with an oil rim below. Tchibouela Main produces from 34 active oil producers. The field came on stream in 1987, had a peak production in 1995 and is now on decline. The current water cut is high. Cenomanian is an excellent reservoir with a strong aquifer and has a high current recovery. The Turonian has more varying reservoir properties, also here the pressure is maintained by natural water influx and one water injector. Both reservoirs are currently on decline. There are two gas producers in Senonian providing gas for gas lift and electricity production. Since Perenco assumed operatorship in 2017, several well workovers; re-perforations and ESP repair/replacements have been performed to maintain and improve production from the field. The Operator plans to continue this programme which is expected to significantly increase production significantly also in 2019. Existing producers are included in the reserves. There is potential for additional infill drilling in Cenomanian and Turonian. As the successful workover programme continues, additional infill wells are classified as contingent resources.

Tchibouela East is a similar smaller dome structure as Tchibouela Main, with Turonian and Cenomanian reservoir levels. The field started production in 1998 with 6 oil producers. The Cenomanian reservoir has had water breakthrough. T0 and T2 of the Turonian reservoir have not been put into production due to gas cap within a thin reservoir, but T1 has been produced. The field closed mid 2016 due to blocking of an export pipe. Production has resumed in 2019 at a moderate level but is expected to increase going forward.

Tchendo Field

Tchendo is an oil field with production from three separate reservoir levels, Senonian, Turonian and Cenomanian with reservoir depths from 450 to 750 mTVDSS. The structure is a gentle dome structure similar to Tchibouela and with similar reservoir qualities. Water depth is 95 m. Tchendo was discovered by exploration well TCDM1 in 1979 and came on stream in 1991. Peak production was reached in 1993 and pressure has been maintained by partial water injection. 16 wells are currently producing, of which seven from the Senonian and nine from Turonian supported by water injection. Water cut is high in Turonian, but still low in Senonian. Cenomanian ceased production in 2009 at a recovery factor of 56%

A similar workover programme to the Tchibouela is being conducted in Techendo with corresponding rate increases.

There is potential for infill drilling in Turonian. As the successful workover programme continues, infill wells are classified as contingent resources.

The Senonian inplace oil volume is very high with yet a modest recovery factor due to poor reservoir properties. This may constitute a significant potential for redevelopment with horizontal producers, possibly with stimulation (fracking). A modest redevelopment programme only has been included as Senonian contingent resources.

Tchibeli Field

Tchibeli is an oil field producing from two reservoir levels in Sendji Fm of Albian age. The upper reservoir is a mix of carbonate and clastics, while the lower is a carbonate reservoir. The reservoir depth is 2000 mTVDSS and the water depth is 100 m. The four-way closure is as a turtle-back structure cut by several faults.

The reservoir quality is fair to good. The field was discovered in 1986 and came on stream in 2000. Peak production was reached shortly after start-up with three oil producers and the field is being pressure maintained by water injection. Production is artificially lifted by ESP (Electrical Submersible Pumps).

This field is the only one in the licence exporting to the Nkossa FPSO. A new export pipeline will be installed from Tchibeli to Tchibouela in 2019. This will make Tchibeli independent of the Nkossa FPSO and realize a significant saving on the related production tariffs.

The production from the existing three producers are included in the reserves. There is potential for some infill drilling in Albian. No infill drilling decision has yet been made in the licence and production from infill drilling is therefore classified as contingent resources.

Tchibeli NE is a smaller, undeveloped Albian discovery north-east of Tchibeli. No information about in-place volumes, nor plans for development, has been presented by the Operator.

Litanzi Field

Litanzi is an oil field producing from Albian Sendji Fm carbonate reservoir. The structure is located northeast of Tchibeli, consists of a relatively thin reservoir zone cut by abundant faults dipping towards the west. The reservoir depth is at 1600 mTVDSS and the water depth is 100 m. Litanzi was discovered in 1990 and started production from one oil producer drilled from the Tchendo platform in 2006. Production is from one producer only and is supported by one water injector and production has, since mid 2016, increased slightly with a stable water-cut.

There is potential for at least one infill well, preferably in the western down-faulted area. No infill drilling decision have yet been made in the licence and production from infill drilling is therefore classified as contingent resources.

PNGF Bis[11]

Three exploration wells have been drilled on the licence area. A discovery in pre-salt Vandji Fm was made in well LUSM-1 on Loussima in 1985. Loussima SW was discovered by well LUSOM-1 in 1987 with oil in Vandji Fm. A second well, SUEM-2, was drilled on Loussima SW in 1991 to appraise the Vandji discovery. Hydrocarbon shows were detected in one of the wells in the Albian post-salt Sendji Fm, (analogue to Tchibeli/Litanzi reservoirs in PNGF Sud). The Sendji interval was not production tested.

The depth to the Vandji reservoir is 3250 mTVDSS, to Sendji around 1940 mVDSS and the water depth in the area is 110 m.

Tests on the Loussima SW LUSOM-1 well produced 4700 bopd and the SUEM-2 well yielded 1150 bopd.

8.4 Trends

PetroNor's revenues are affected by changes in commodity prices, specifically crude oil and natural gas prices. During 2018 crude oil prices averaged 69 USD/bbl and were higher than in 2017 on average, although fluctuations occured. In December 2018, oil prices dropped to around USD 54/bbl, but have now recovered to trading around USD 65/bbl, which has a material impact on PetroNor's earnings.

The oil from PNGF Sud is sold by the local company HEPCO. HEPCO has as of 1 January 2019 entered into a new oil sales agreement contract, as described in Section 8.6.2 "Material contracts" below.

8.5 Litigation, disputes and tax

Hemla Africa Holding AS has received a notice of dispute from Mr. Kostveit concerning ownership in HEPCO. Mr. Kostveit argues that he is entitled to a larger ownership position in HEPCO, including past dividends taking such ownership position into account, based on an alleged oral agreement with Mr. Ludvigsen, Mr. Søvold and Petromal. The notice has also gone to Mr. Ludvigsen and Mr. Søvold directly. The claim is disputed. To the extent the claim should be adversely determined against Hemla Africa Holding AS, NOR, has agreed to provide an indemnification, on certain conditions and subject to certain limitations, for any reduction in value of the indirect ownership in HEPCO resulting from such adverse outcome. There are ongoing discussions also with other minority stakeholders in HEPCO regarding their right to (indirect) ownership in HEPCO, but these are expected to be dealt with through distribution of indirect ownership in HEPCO which will not impact PetroNor. There are also certain ongoing discussions with MGI relating to *inter alia* a USD 7 million loan granted to MGI, where the main issue is whether HEPCO or Hemla Africa Holding AS should be the creditor for the loan.

Hemla Africa Holding AS is in dispute with the local partner Paul-Marie Taty-Mouanda concerning (indirect) ownership in HEPCO. Mr. Taty-Mouanda argues that he is entitled to an (indirect) ownership position in HEPCO, including past dividends taking such ownership position into account. Mr. Taty-Mouanda has filed the claim before the Commercial Court in Pointe-Noire and the legal hearings are expected to commence by the end of April. Mr. Taty-Mouanda has also filed a petition for arrest, relating to Hemla Africa Holding AS' shares in HEPCO. The claim is based on an alleged agreement with Hemla Africa Holding AS, MGI, Petromal and the other local partners. The claim is disputed.

[11] The PNGF Sud partnership has through an agreement dated 9 February 2017 a right to negotiate in good faith the licence terms with the Republic of Congo.

Pursuant to a new finance law effective 1 January 2019, changes were made to the general tax code in Congo, whereafter conventions, contracts or other agreements of any kind entered into by the Congolese authorities and which provides for tax benefits derogating from the provisions of the general tax code, shall be presented to the Ministry of Finance in Congo and be subject to renegotiations. Perenco as operator of the relevant PNGF Sud PSCs licences have submitted these, and there are ongoing discussions with the authorities on whether inter alia a withholding tax will be imposed on dividend payments from contractors that are parties to PSCs such as the ones for PNGF Sud. These changes and discussions are not specific to PNGF Sud or to HEPCO but apply to the oil and gas industry in Congo in general.

Except to the extent disclosed above, neither PetroNor nor any other company in the PetroNor group is, nor has been, during the course of the preceding twelve months involved in any legal, governmental or arbitration proceedings which may have, or have had in the recent past, significant effects on PetroNor’s and/or the PetroNor group’s financial position or profitability, and PetroNor is not aware of any such proceedings which are pending or threatened.

8.6 Material contracts

8.6.1 Disclosure about dependency on contracts, patents and licences

PetroNor's activities in PNGF Sud are carried out through its subsidiary HEPCO under three production sharing contracts, in which PetroNor holds a 10.5% indirect interest through HEPCO. It is crucial for PetroNor's business that HEPCO remains party to the PSCs, and that the contracts referenced below are not revoked.

8.6.2 Material contracts

HEPCO holds three production sharing contracts, "Contrat de Partage de Production Tchendo II", "Contrat de Partage de Production Tchibouela II" and "Contrat de Partage de Production Tchibeli-Litanzi II". Under the tender award the contractor group entered into an umbrella agreement for PNGF Sud which in addition to the above three Production Sharing Contracts ("PSCs") also holds the right to negotiate, in good faith, licence terms to enter into a PSC on the adjacent licence PNGF Bis. The licence terms for PNGF Bis are currently negotiated by Perenco, the Operator, on behalf of the PNGF Sud licence partners.

The subsidiary of PetroNor, HEPCO, has entered into an oil sales agreement with ENI to sell all of HEPCO's share of the oil extracted from PNGF Sud. HEPCO is producing two qualities of crude oil, Djeno blend and Nkossa Blend which both are piped to the Djeno terminal outside of Pointe Noire in the Republic of Congo. ENI is lifting both qualities on a monthly basis and HEPCO has entered into a pooling agreement with ENI for co-loading with ENI from 1 January 2019 and until 31 December 2021. The crude oil (Djeno and Nkossa Blend) is sold FOB on monthly average price linked to Brent DTD as published by Platts. The final contract price is adjusted for quality and the differential is negotiated for each cargo lifted. In 2018, the price adjustment averaged USD 2/bbl.

8.7 Board of directors, management and employees

8.7.1 Board of directors

The board of directors of PetroNor consists of Eyas Alhomouz as Chairman (Chief Executive Officer of Petromal), Knut Søvold, Gerhard Ludvigsen and Hawary Marshad.

8.7.2 Management and employees

PetroNor's executive management consists of four individuals, Eyas Alhomouz as executive Chairman, Usama Saeed Ali as financial controller, Knut Søvold as chief executive officer and Gerhard Ludvigsen as executive director. PetroNor's organisation has twelve employees.

8.8 Selected financial information of PetroNor

8.8.1 Introduction

The following selected financial information has been extracted from the unaudited financial statements for PetroNor for the year ended 31 December 2017 and the unaudited financials for the year ended 31 December 2018. The historical results of PetroNor are not necessarily indicative of its results for any future period. For a discussion of certain risks that could impact the business, operating results, financial condition, liquidity and prospects of PetroNor, see Section 1 "Risk Factors".

The annual accounts of PetroNor have been prepared in accordance with IFRS as adopted by the European Union.

8.8.2 PetroNor income statement

The tables below set out a summary of information extracted from the unaudited income statement of PetroNor for the year ended 31 December 2017 and unaudited results for the year ended 31 December 2018.

	For the Years ended 31 December	
(USD million)	**2018**	**2017**
	Unaudited	*Unaudited*
Sale of oil	85.81	57.94
Other revenue	-	-
Total revenue	**85.81**	**57.94**
Cost of sales	(26.32)	(19.70)
Exploration expense	-	-
Administrative expense	(9.04)	(3.43)
Other income	0.49	-
Total Operating profit	**50.94**	**34.81**
Finance cost	(2.62)	(0.88)
Interest expense Foreign exchange gain / (loss)	(0.09)	(0.16)
Profit before income tax	**48.24**	**33.77**
Income tax	(31.12)	(22.62)
Profit for the year	**17.11**	**11.15**
Attributable to:		
Equity holders of the parent	7.86	5.85
Non-controlling interest	9.25	5.30
	17.11	**11.15**

8.8.3 PetroNor statements of financial position

The tables below set out a summary of information extracted from the unaudited balance sheet of PetroNor for the year ended 31 December 2017 and unaudited balance sheet for the year ended 31 December 2018.

	For the years ended 31 December	
(USD million)	**2018**	**2017**
	Unaudited	*Unaudited*
ASSETS		
Non-current assets		
Intangible assets	5.56	6.46
Tangible assets	12.58	10.85
Total non-current assets	**18.15**	**17.31**
Current assets		
Inventory	2.57	2.37
Trade & other receivables	28.10	7.01
Cash & cash equivalents	7.93	8.07
Total current assets	**38.71**	**17.48**
TOTAL ASSETS	**56.85**	**34.80**
EQUITY & LIABILITIES		
Equity		
Share capital	0.12	0.12
Statutory reserve	0.17	-
Retained earnings	13.59	5.85
Equity attributable to equity holders of the Company	**13.88**	**5.97**
Non-controlling interest	12.80	5.71
Total equity	**26.68**	**11.68**
Non-current liabilities		
Decommissioning cost liability	13.50	12.67
Loan	7.08	-
Current liabilities		
Accounts payable & accrued liabilities	9.60	10.44
Total liabilities	**30.18**	**23.11**
TOTAL EQUITY & LIABILITIES	**56.86**	**34.79**

8.8.4 PetroNor statements of cash flows

The tables below set out a summary of information extracted from the unaudited statement of cash flows of PetroNor for the year ended 31 December 2017 and unaudited statement of cash flows for the year ended 31 December 2018.

	For the Years ended 31 December	
(USD million)	**2018**	**2017**
	Unaudited	*Unaudited*
OPERATING ACTIVITIES		
Profit for the year	17.12	11.15
Adjustments for:		
Depreciation & amortization	3.21	2.51
Unwinding of discount on decommissioning liability	0.82	0.77
Cash flow from operating activities	**21.15**	**14.44**
Working capital adjustments:		
Accounts receivable & prepayments	(21.17)	(7.04)
Inventory	(0.20)	(2.37)
Accounts payable & accruals	(0.83)	10.44
Cash from operations	**(22.12)**	**1.06**
Net cash from operating activities	**(1.06)**	**15.46**
INVESTING ACTIVITIES		
Purchase of non-current assets	(4.04)	(7.92)
Proceeds from sale of non-controlling interest	-	0.41
Net cash used in investing activities	**(4.04)**	**(7.51)**
FINANCING ACTIVITIES		
Share capital	-	0.12
Dividend paid to non-controlling interest	(2.12)	-
Proceeds from loan	7.08	-
Net cash from financing activities	**4.96**	**0.12**
INCREASE IN CASH & CASH EQUIVALENTS	**(0.14)**	**8.07**
Cash & cash equivalents at 1 January	8.07	-
CASH & CASH EQUIVALENTS AT 31 DECEMBER	**7.93**	**8.07**

8.9 Significant change

Other that the Transaction described in Section 4 "Description of the Transaction", there has been no significant change in the financial or trading position of PetroNor since the end of the last reporting period.

8.10 Fiscal and environmental conditions relating to Congo

Under PNGF Sud, there are fiscal terms specific to each assets. The partners in the license pay a royalty of 15%. There is a cost stop ranging from 50% to 55%. Further, the parties pay a profit oil dependent on cumulative oil produced from the individual fields: 50% until 20 mmbbl and thereafter 45% (Tchibouela), 50% until 15mmbbl (Tchendo) and 50% (Tchibeli/Litanzi). In addition, there is a super profit receivable, calculated as the differential of the actual achieved oil price and a ceiling price (which is only applicable if super profit is above zero). The price ceiling covers the maximum amount of cost oil to be recovered and super profit. As a summary, the netback is around 30% of the realised oil price.

PetroNor is not obliged to carry out environmental protection measures that would be significant to the business or financial situation. However, all phases of the oil business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and state and municipal laws and regulations. Environmental legislation provides for, amongst other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Elements of PetroNor’s activities, products or services that can interact with the environment are produced formation water including chemicals, emission of greenhouse gases and the risk of acute oil discharges including loss of well control. To the extent PetroNor can control and influence the environmental aspects in the licenses are dependent on its status as partner and is fundamental to the practical application of the PetroNor’s environmental management system.

The primary responsibility for the environmental management of the activities within the license area rests with the designated operator. However, as PetroNor holds joint and shared liability in connection with any environmental damage from activities undertaken in the license block, it is in PetroNor’s best interest from a risk management perspective to ensure that the operator has environmental management provisions that are consistent with its environmental standards. As such, PetroNor assesses and aligns its environmental management provisions with those of the operator.

PetroNor is committed to identify all its aspects and impacts, shall assess their significance, and ensure that appropriate operational controls are in place for those considered to be significant.

PetroNor applies a broad definition of ‘environmental aspects’ and considers that, in addition to the physical activities that could lead to an environmental impact, the selection of other operators with whom PetroNor chooses to invest (as a partner) in a license group is also an aspect which can influence the occurrence and/or extent of potential environmental impacts. Similarly, PetroNor’s selection of contractors to undertake activities on its behalf where it is the operator is also an aspect that can influence the extent of potential environmental impacts.

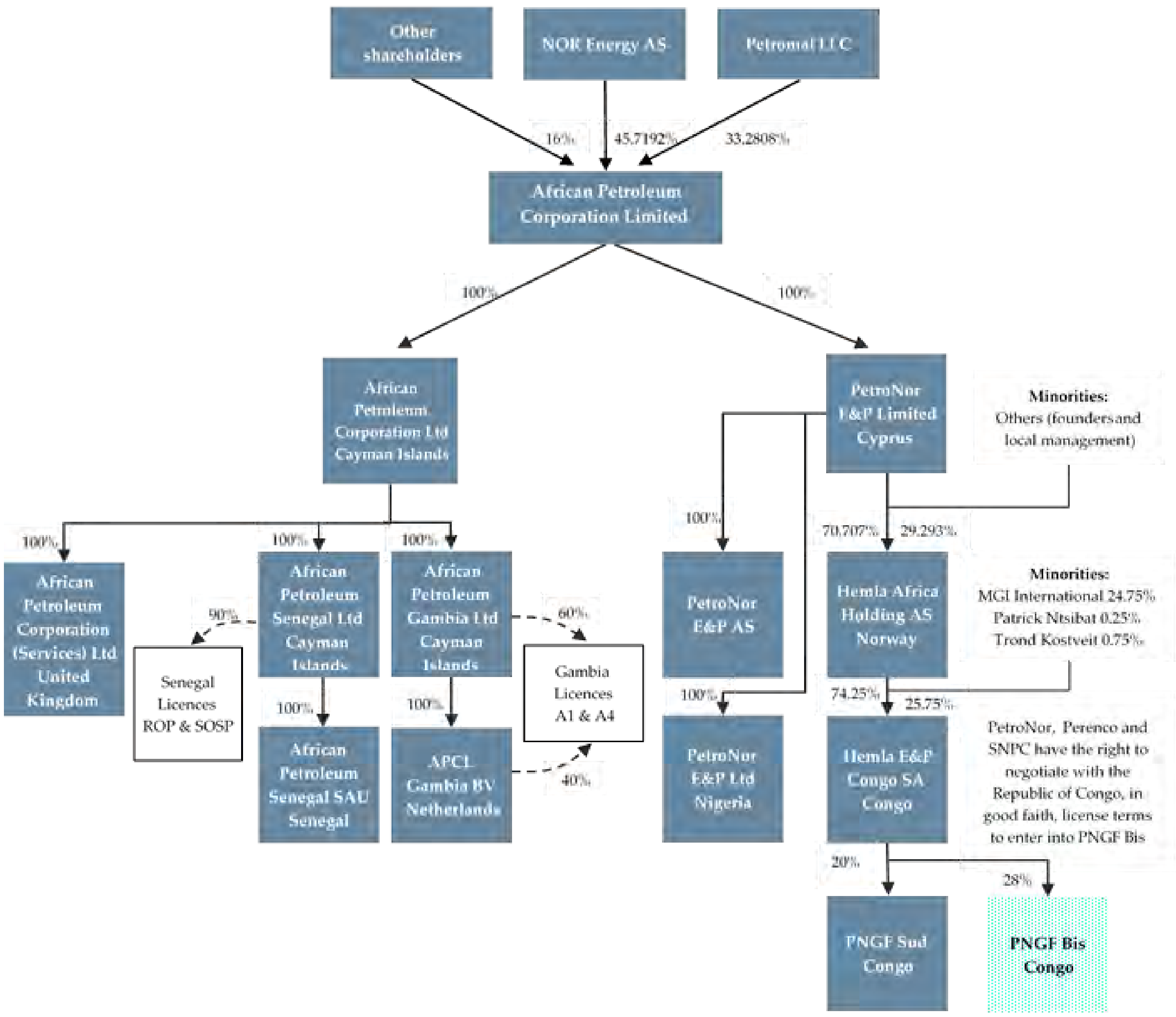
9 THE COMBINED COMPANY

9.1 The Company following Completion of the Transaction

Through the Transaction, African Petroleum will acquire diversified, low risk, long life and high quality producing assets with competitive unit costs and a well-regarded, efficient operator in PNGF Sud (Perenco). The Transaction will transform the Company from a pure-play exploration company into a full cycle E&P company with material reserves, cash flow and significant upside potential.

9.2 Legal structure

The figure below sets forth a condensed legal structure of the Combined Group following completion of the Transaction:



9.3 Organisational changes

9.3.1 Overview of the Board of Directors and Management following the Transaction

Following completion of the Transaction, the parties have agreed that Jens Pace will continue as the Chief Executive Officer, Stephen West will continue as the Chief Financial Officer and Michael Barrett will continue as Exploration Director. The co-founders of PetroNor, Knut Søvold and Gerhard Ludvigsen, will become Chief

Operating Officer and Business Development Manager respectively, and Claus Frimann-Dahl will be appointed Chief Technical Officer.

Furthermore, it is proposed to the shareholders of African Petroleum that Eyas Alhomouz. Knut Søvold, Joseph Iskander will join the Board of Directors of the Company. Further, Eyas Alhomouz will assume the role as Chairman. Jens Pace, Stephen West, Bjarne Moe, David King, and Timothy Turner will remain board members following completion of the Transaction.

Other than Eyas Alhomouz, Joseph Iskander and Knut Søvold, all the members of the Board of Directors following the Transaction are independent of the majority shareholders. All Directors except for Jens Pace, Stephen West and Knut Søvold are independent of the Company's executive management.

9.3.2 Brief biographies of the new members of Board of Directors and Management

Eyas Alhomouz (proposed Chairman of the Board of Directors)

Mr. Alhomouz has a strong experience from the oil and gas sector covering the US, 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 a COO and Financial 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 a General Manager of Jaidah Energy, an Omani-Qatari owned company servicing the oil and gas sector in Qatar. Mr. Alhomouz graduated from Brigham Young University in Provo, UT with a degree in Chemical Engineering and from the Colorado School of Mines, in Golden, CO with a master's degree in Mineral and Energy Economics.

Knut Søvold (proposed Director and Chief Operating Officer)

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

Gerhard Ludvigsen (proposed Business Development Manager)

Mr. Ludvigsen is the founder of several companies in Norway 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 Solution 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. He has recently established PetroNor with Petromal. He serves on the board of the charity foundation Power to Educate which supports education in emerging countries.

Claus Frimann-Dahl (proposed Chief Technical Officer)

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. He holds a BSc in Petroleum Engineering from Texas A&M University and an MSc from the University of Trondheim (NTH).

Joseph Iskander (proposed Director)

Mr. Joseph Iskander joined Emirates International Investment Company in July of 2017 as the Director of Private Equity. He is responsible for spearheading and managing EIIC's investments. 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. Before joining EIIC, 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 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. Prior to joining Dubai Group, Mr. Iskander headed the research team at Egypt's Prime Investments and was earlier an Investment Advisor at Commercial International Bank (CIB). 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. He holds a Degree in Accounting and Finance with high distinction from Helwan University, Egypt (1997).

9.4 Business strategy following Completion of the Transaction

The Company's vision is to be a full-cycle, Africa focused E&P company focusing on producing assets with upside and development of stranded assets, combined with targeted high impact exploration. The combined Company will aim to steadily build and increase its reserve base and production while using free cash flow to pursue defined exploration targets in selected and highly prospective basins with a view to delivering significant value to its shareholders from high impact wells. With the enhanced financial strength, the Company seeks to rigorously protect its position in The Gambia and Senegal through reinstatement of its licences and subsequent farm-outs to ensure drilling of wells without exposing the balance sheet of the Company.

9.5 The Transaction's significance for earnings, assets and liabilities of the Combined Group

The Transaction will have a significant effect on the key figures of the Combined Group compared to the Group prior to the Transaction. With reference to the pro forma financial information in Section 10 "Pro forma financial information", the Combined Group would have had total revenues of USD 58,615,000 in 2017. Total assets for the Combined Group would have amounted to USD 57,117,000 as of 31 December 2017.

See Section 10 "Pro forma financial information" below for a further description of the Transaction's significance for the earnings, assets and liabilities of the Combined Group. The pro forma financial information in Section 10 "Pro forma financial information" addresses a hypothetical situation and does not represent the actual financial statements of the Combined Group. The pro forma financial information is based on judgments and assumptions made by the management of Company that might not necessarily have occurred had the Transaction been made at an earlier time.

For additional information regarding the Transaction's significance, including strategic effects, reference is made to Section 4.3 "Background and reason for the Transaction".

10 PRO FORMA FINANCIAL INFORMATION

10.1 Unaudited pro forma financial information

The acquisition of PetroNor resulted in "a significant gross change" for the Company, as defined in Commission Regulation (EC) No. 809/2004 of 29 April 2004 which sets out the requirements to the Pro Forma financial information which needs to be included in an Information Memorandum. For the purpose of complying with this, the Company has prepared the pro forma statements of financial position and comprehensive income so as to illustrate how the acquisition of PetroNor would have affected the Company had the Transaction been completed on 1 January 2017. It is currently expected that completion of the Transaction will take place on or around 30 April 2019.

Apart from the Transaction, no other circumstances occurring after 31 December 2017 are covered by the pro forma statements financial information. The sources of the historical financial information included in the pro forma financial statements are:

- For the Company, extracted from the audited consolidated financial statements as of 31 December 2017;
- For PetroNor E&P Ltd, extracted from the audited financial statements of Hemla Africa Holdings AS as of 31 December 2017, the audited financial statements of Hemla E&P Congo SA as of 31 December 2017 and the unaudited financial statements of PetroNor as of 31 December 2017, as per Section 10.7 "PetroNor condensed consolidated financial statements".

10.2 General information and purpose of the unaudited pro forma comprehensive financial information

In the preparation of the pro forma financial information, the Transaction has been considered a reverse takeover, but not a business combination. PetroNor is considered as the accounting acquirer and APCL as the accounting acquiree.

The pro forma financial information has been compiled solely to comply with Annex II of Regulation (EC) 809/2004 in the Prospectus Directive. The pro forma financial information has been prepared for illustrative purposes only, as if the Transaction had occurred on 1 January 2017. Because of its nature, the pro forma financial information addresses a hypothetical situation and, therefore, does not represent the Group's actual financial position.

The assumptions underlying the pro forma adjustments and the principles of reverse takeover accounting are described in the notes to the pro forma information included in Section 10.5 "Note to the pro forma financial information". The resulting pro forma financial information has not been audited in accordance with Norwegian or International Standards on Auditing ("ISAs").

However, the Company's independent accountant, BDO (WA) Pty Ltd, has issued a report on the Pro Forma financial information included in Appendix C hereto. The report is prepared in accordance with ISAE 3420 "Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus".

The pro forma financial information does not include all of the information required for financial statements prepared under Australian Accounting Standards, because the pro forma financial information reflects a hypothetical situation, it neither represents the actual combination of the financial statements of the Company and PetroNor nor the Group's financial position as of 31 December 2017. Since certain simplifications and assumptions have been made as discussed in Section 10.5 "Notes to the pro forma financial information".

Although management has endeavoured to prepare the pro forma financial information using the best available information, the Pro Forma financial information must not be considered final or complete; and may be amended in future publications of accounts. Investors are cautioned not to place undue reliance on the pro forma financial information.

10.3 Accounting principles

The underlying financial information for the Group as of 31 December 2017 included in the pro forma financial information is extracted from financial statements that have been prepared under Australian Accounting Standards and also complies with IFRS as issued by the International Accounting Standards Board. PetroNor prepares its respective consolidated financial statements in accordance with Norwegian GAAP, though management has not identified any differences between the Company's accounting policies and those applied that would impact the pro forma financial information.

10.4 Unaudited pro forma comprehensive financial information

Pro forma statement of comprehensive income for the year ended 31 December 2017

USD '000	**PetroNor Consolidated Unaudited[1]**	**APCL Consolidated Audited**	NGAAP / IFRS Adjustments	Pro Forma Adjustments	**Pro Forma Income Statement Reviewed**
OPERATING INCOME AND EXPENSES					
Revenue					
Oil sales	**57,936**	-	-	-	**57,936**
Other	-	**229**	-	-	**229**
Operating Income	**57,936**	**229**	**-**	**-**	**58,165**
Cost of sales	**(19,698)**	-	**-**	**-**	**(19,698)**
Exploration costs	**-**	**(9,856)**	-	-	**(9,856)**
Exploration impairment	**-**	**(18,368)**	-	-	**(18,368)**
Payroll expenses	**(1,000)**	**(4,387)**	-	-	**(5,387)**
Legal and professional fees	**(206)**	**(1,667)**	-	-	**(1,873)**
Travel	**(800)**	**(477)**	-	-	**(1,277)**
Other operating costs	**(1,579)**	**(560)**	-	-	**(2,139)**
Share based payment – Costs of listing	-	-	-	(7,499)	**(7,499)**
Operating expenses	**(23,283)**	**(35,315)**	**-**	**(7,499)**	**(66,097)**
OPERATING PROFIT / (LOSS)	**34,653**	**(35,086)**	**-**	**(7,499)**	**(7,932)**
FINANCIAL INCOME AND EXPENSES					
Other interest expenses	**(105)**	**(3)**	-	-	**(108)**
Other financial expenses	**(773)**	**(8)**	-	-	**(781)**
Gains on derivatives	**-**	**78**	-	-	**78**
NET FINANCIAL INCOME AND EXPENSES	**(878)**	**67**	-	-	**(811)**
OPERATING RESULT BEFORE TAX	**33,775**	**(35,019)**	**-**	**(7,499)**	**(8,743)**
Tax on ordinary result	**(22,620)**	**-**	-	-	**(22,620)**
OPERATING RESULT AFTER TAX	**11,155**	**(35,019)**	**-**	**(7,499)**	**(31, 363)**
OTHER COMPREHENSVE GAINS					

USD '000	PetroNor Consolidated Unaudited[1]	APCL Consolidated Audited	NGAAP / IFRS Adjustments	Pro Forma Adjustments	Pro Forma Income Statement Reviewed
Foreign currency translation reserve					
Foreign exchange loss on translation of functional currency to presentation currency	**-**	**(34)**	-	**-**	**(34)**
TOAL COMPREHENSIVE RESULT	**11,155**	**(35,053)**	-	(7,499)	**(31, 397)**
Operating result after tax:					
Non-controlling interest	**7,970**	**(399)**	-	(6,739)	832
Owners of the parent	**3,185**	**(34,620)**	-	(760)	(32,195)
Total comprehensive result:					
Non-controlling interest	**7,970**	**(399)**	-	(6,739)	832
Owners of the parent	**3,185**	**(34,654)**	-	(760)	(32,229)

1 PetroNor parent company and consolidated financial information has not been audited, though subsidiary companies have been audited as per Section 10.7 "PetroNor condensed consolidated financial statements".

Pro forma statement of financial position as at 31 December 2017

USD '000	PetroNor Consolidated Unaudited[1]	APCL Consolidated Audited	NGAAP / IFRS Adjustments	Pro forma Adjustments	Pro forma Financial Position Reviewed
ASSETS					
CURRENT ASSETS					
Cash and cash equivalents	**8,069**	**13,186**	-	(2,126)	**19,129**
Trade and other receivables	**7,043**	**240**	-	-	**7,283**
Inventories	**2,369**	**-**	-	-	**2,369**
Restricted cash	**-**	**903**	-	-	**903**
TOTAL CURRENT ASSETS	**17,481**	**14,329**	-	(2,126)	**29,684**
NON CURRENT ASSETS					
Inventories	**-**	**1,007**	-	-	**1,007**
Property, plant and equipment	**460**	**4**	-	-	**464**
Exploration and production licences	**16,845**	**9,108**	-	-	**25,953**
Goodwill	**9**	**-**	-	-	**9**
TOTAL NON CURRENT ASSETS	**17,314**	**10,119**	-	-	**27,433**
TOTAL ASSETS	**34,795**	**24,448**	-	(2,126)	**57,117**
LIABILITIES					
CURRENT LIABILITIES					
Trade payables	**4,413**	**3,496**	-	-	**7,909**

USD '000	PetroNor Consolidated Unaudited[1]	APCL Consolidated Audited	NGAAP / IFRS Adjustments	Pro forma Adjustments	Pro forma Financial Position Reviewed
Other payables	**6,026**	**9,793**	-	-	**15,819**
TOTAL CURRENT LIABILITIES	**10,439**	**13,289**	-	-	**23,728**
NON CURRENT LIABILITIES					
Provisions	**12,672**	**-**			**12,672**
TOTAL NON CURRENT LIABILITIES	**12,672**	**-**	-	-	**12,672**
TOTAL LIABILITIES	**23,111**	**13,289**	-	-	**36,400**
NET ASSETS	**11,684**	**11,159**	-	(2,126)	**20,717**
EQUITY					
Issued capital	**120**	**643,438**	-	(593,758)	**49,800**
Reserves	**(2)**	**21,253**	-	(19,382)	**1,869**
Retained earnings / (losses)	**3,180**	**(650,086)**	-	609,168	**(37,738)**
Parent interests	**3,298**	**14,605**	-	(3,972)	**13,931**
Non-controlling interests	**8,386**	**(3,446)**	-	1,846	**6,786**
TOTAL EQUITY	**11,684**	**11,159**	-	(2,126)	**20,717**

1 PetroNor parent company and consolidated financial information has not been audited, though subsidiary companies have been audited as per Section 10.7 "PetroNor condensed consolidated financial statements".

10.5 Notes to the pro forma financial Information

In the Pro Forma financial information, the acquisition is accounted for as a continuation of the financial statements of PetroNor. The Transaction assessed fair value excess of the over the net assets of APCL and an estimate for listing expenses has been expensed as a share-based payment. The estimate for listing expenses is based on the deemed market capitalisation of the company less the net assets acquired as outlined below.

Fair Value		**US$ 000**
APCL issued shares currently in issue	155,466,446	
APCL share price used in Pro Forma calculations	NOK 1.05	
Foreign exchange rate NOK : USD	USD $0.1207	
Fair value consideration		**18,760**

Share capital	**US$ 000**	**US$ 000**
APCL issued capital as at 1 January 2017	611,455	
PetroNor issued capital as at 1 January 2017	120	611,575
APCL issue of shares and capital raising costs		31,983

Pro Forma adjustments		
Elimination of APCL issued capital at 1 January 2017	(611,455)	
PetroNor issued capital for APCL acquisition	18,760	
Costs associated with the APCL acquisition	(1,063)	(593,758)
Post transaction		**49,800**

Retained earnings / Accumulated losses	**US$ 000**	**US$ 000**
APCL accumulated losses as at 1 January 2017	(615,467)	
PetroNor accumulated losses as at 1 January 2017	(3)	(615,470)
APCL loss for the year	(34,620)	
PetroNor profit for the year	3,184	(31,436)
Pro Forma adjustments		
Elimination of APCL accumulated losses as at 1 January 2017	615,467	
Reflect minority interest of APCL	(6,299)	609,168
Post transaction		**(37,738)**

Share based payment – Costs of listing	**US$ 000**	**US$ 000**
Pro Forma adjustments		
PetroNor issued capital for APCL acquisition	18,760	
Cash utilised for Transaction costs	2,126	
Proportion of Transaction costs attributable to the issue of shares[12]	(1,063)	
Fair value of APCL net assets acquired as at 1 January 2017	(12,324)	7,499
Post transaction		**7,499**

As the fair value consideration is calculated using the share price of APCL, consideration will change on a daily basis. Consequently the Pro Forma financial information has used the trading share price several days before the release of this Information Memorandum to allow time for the Company's independent accountant to complete their report.

If the APCL share price was to move by +/- 5% from the NOK 1.05 figure used in the pro forma financial information, the variance in the fair value consideration is as follows:

APCL share price	NOK 1.00	NOK 1.05	NOK 1.10
Fair value consideration	USD 17,830,000	18,760,000	19,700,000
Increase/(decrease) in share based payment	USD (930,000)	-	USD 940,000
Increase/(decrease) in share capital	USD (930,000)	-	USD 940,000

10.6 Independent assurance report on audited pro forma financial information

BDO (WA) Pty Ltd has issued a report on the pro forma financial information. The report is included in Appendix C in this Information Memorandum.

[12] The pro forma financial information assumes that 50% of the cash used to pay the Transaction costs was directly attributable to the issue of shares for cash and would have been avoided if the Transaction had not occurred, consequently these costs are deducted from equity.

10.7 PetroNor condensed consolidated financial statements

On the 1 July 2018, a group restructure took place whereby the shareholders of Hemla Africa Holding AS ("HAH AS") were provided shares in PetroNor E&P Ltd at the same ratio to their shareholding in Hemla Africa Holding AS. This restructure took place under common control and under the principles of continuance accounting had no impact in terms of fair value adjustments.

On 30 December 2018, 29.293% of the share capital of HAH AS was sold to Symero Limited, a 100% subsidiary of NOR Energy AS, the controlling shareholder of PetroNor E&P Ltd. PetroNor E&P Ltd retained control of HAH AS after the transaction. The consideration for the 29.293% shareholding was of nominal value, and no fair value adjustment to the investment has been made. Any fair value in excess of the consideration would have been recognised as an extraordinary loss on disposal, with an opposite entry to minority interests. Consequently the net equity for PetroNor E&P Ltd would remain constant.

For the purposes of the pro forma financial information it is assumed that the group restructure and disposal of shares to Symero Limited took place on the 1 January 2017.

Condensed consolidated profit and loss for the year ended 31 December 2017

USD '000	**Hemla Africa Holding AS Consolidated Unaudited***	**PetroNor E&P Ltd Unaudited**	Consolidation Adjustments	**PetroNor E&P Ltd Consolidated Unaudited**
Operating Income	57,936	-	-	57,936
Operating expenses	(23,279)	(4)	-	(23,283)
OPERATING PROFIT / (LOSS)	**34,657**	**(4)**	-	**34,653**
Financial expenses	(878)	-	-	(878)
OPERATING RESULT BEFORE TAX	**33,779**	**(4)**	**-**	**33,775**
Tax on ordinary result	(22,620)	-	-	(22,620)
OPERATING RESULT AFTER TAX	**11,159**	**(4)**	**-**	**11,155**
Operating result after tax:				
Minority share	5,304	(2)	2,668	7,970
Majority share	5,855	(2)	(2,668)	3,185

Condensed consolidated balance sheet as at 31 December 2017

USD '000	**Hemla Africa Holding AS Consolidated Unaudited***	**PetroNor E&P Ltd Unaudited**	Adjustments	**PetroNor E&P Ltd Consolidated Unaudited**
Current assets	17,361	120	-	17,481
Non current assets	17,305	3	6	17,314
Total assets	**34,666**	**123**	6	**34,795**
Current liabilities	10,432	7	-	10,439
Non current liabilities	12,672			12,672
Total liabilities	**23,104**	**7**		**23,111**
Net assets	**11,562**	**116**	6	**11,684**

Condensed consolidated balance sheet as at 31 December 2017

USD '000	**Hemla Africa Holding AS Consolidated Unaudited***	**PetroNor E&P Ltd Unaudited**	Adjustments	**PetroNor E&P Ltd Consolidated Unaudited**
Share capital	4	120	(4)	120
Reserves	(2)	-	-	(2)
Retained earnings / (losses)	5,844	(2)	(2,662)	3,180
Parent interests	5,846	118	(2,666)	3,298
Minority interests	5,716	(2)	2,672	8,386
Equity	**11,562**	**116**	6	**11,684**

*The consolidated financial statements for Hemla Africa Holding AS have been prepared under Norwegian GAAP, with NOK as the presentational currency. The USD figures in the condensed statements above have been translated from the NOK values. The operating subsidiary Hemla E&P Congo SA prepared financial statements under Congolese GAAP that were audited by Ernst & Young Congo. Management identified that adjustments were necessary to adjust between NGAAP and IFRS when consolidating Hemla African Holding AS. These adjustments that have not been audited.

Principal NGAAP / IFRS adjustments for Hemla E&P Congo SA included the recognition of a $12.7 million provision for decommissioning costs, plus the netting off of $10.4 million cost of sales with revenue, to present oil sales revenue on an entitlement method basis.

Management considered the acquisition of the Congolese licences by Hemla E&P Congo SA an asset-based transaction and not a business combination, therefore IFRS 3 was not applied when accounting for the original acquisition.

11 ADDITIONAL INFORMATION

11.1 Documents on display

Copies of the following documents will, during a period of 12 months following the publication of this Information Memorandum, be available for inspection at any time during normal business hours on any business day free of charge at the Company's offices at 48 Dover Street, London, W1S 4FF, United Kingdom or requested by telephone: +44 (0) 203 655 7810 or downloaded from the Company's web-page: www.africanpetroleum.com.au:

- the Memorandum and Articles of Association of the Company;
- all reports, letters, and other documents, historical financial information, valuations and statements prepared by any expert at the Company's request any part which is included or referred to in this Information Memorandum;
- the historical financial information for the Company and its subsidiary undertakings for each of the two financial years preceding the publication of this Information Memorandum; and
- this Information Memorandum, including appendices.

11.2 Incorporation by reference

The information incorporated by reference in this Information Memorandum should be read in connection with the cross-reference list set out in the table below. Except as provided in this Section, no other information is incorporated by reference in this Information Memorandum. The Company incorporates by reference the Company's audited consolidated financial statements as at, and for the years ended, 31 December 2017, 2016 and 2015, and the Group's unaudited consolidated financial statements as at, and for the six month periods ended, 30 June 2018 and 2017, as well as certain other documents specified below.

Section in the Information Memorandum	Disclosure requirement	Reference document and link	Page (P) in the reference document
Section 6.3	Audited historical financial information (Annex I, Section 20.1)	**Financial statements 2017:** https://newsweb.oslobors.no/message/452905	P 24 - 51
		Financial statements 2016: https://newsweb.oslobors.no/message/427601	P 33 - 66
		Financial statements 2015: https://newsweb.oslobors.no/message/401555	P 37 - 80
	Audit report (Annex I, Section 20.4.1)	**Audit's report 2017:** https://newsweb.oslobors.no/message/452905	P 52 - 53
		Audit's report 2016: https://newsweb.oslobors.no/message/427601	P 67 - 69
		Audit's report 2015: https://newsweb.oslobors.no/message/401555	P 81
Section 6.1	Accounting policies (Annex I, Section 20.1)	**Accounting principles:** https://newsweb.oslobors.no/message/452905	P 28 – 34
Section 6.3	Interim financial information (Annex I, Section 20.6.1)	**Interim financial statements H1 2018:** https://newsweb.oslobors.no/message/458535	P 1 – 17
		Interim financial statements H1 2017: https://newsweb.oslobors.no/message/433863	P 1 – 19

12 DEFINITIONS AND GLOSSARY

12.1 Definitions

African Petroleum	African Petroleum Corporation Limited
APCL Replacement Performance Options	The 8,513,848 new performance options that will replace the 15,740,000 existing options issued to the Company's Board, management and consultants in connection with the Transaction
APCL Warrants	The 155,466,446 warrants to be allocated among the existing shareholders of the Company at the date of the general meeting required to approve the Transaction
APCL Warrants Vesting Event	Either (a) the reinstatement of the A1 and A4 licences in The Gambia or (b) the reinstatement of the SOSP licence in Senegal, whichever comes first, and (y) a farm-in agreement to such licence(s) being signed and legally binding, where the Company will be fully carried for the current phase work program under the licence(s), on commercially acceptable terms approved by the Board of Directors
ASIC	Australian Securities and Investments Committee
ASX	Australian Securities Exchange
AUD	Australian Dollars, the lawful currency of Australia
Australian Corporations Act	The Australian Corporations Act of 2001
Australian Custodian	Citibank Melbourne
Board of Directors or Board	The board of directors of the Company
BDO	BDO Audit (WA) Pty Ltd
BP	BP Exploration Operating Company Limited
CGC	The ASX Corporate Governance Council
Company	African Petroleum Corporation Limited
Consideration Shares	The 816,198,842 new shares in the Company to be issued to NOR and Petromal as consideration in the Transaction
Continuing Obligations	The Continuing Obligations for Stock Exchange Listed Companies
CPR	Competent Persons Report
Directors	Members of the Board of Directors of the Company
Economic ownership	The economic ownership interest to PetroNor, divided into 54.428% for NOR and 45.572% for Petromal
EHL	European Hydrocarbons Limited (UK)
ENI	ENI Trading and Shipping SPA
ERC Equipoise	ERC Equipoise Ltd
Existing Assets	The Company's hydrocarbon licences in The Gambia and Senegal
FIRB	The Australian Foreign Investment Review Board
Forward-looking statements	Statements, including, without limitation, projections and expectations regarding the Group's future financial position, business strategy, plans and objectives, and statements such as "anticipate", "believe", "estimate", "expect", "seek to" and similar expressions, as they relate to the Company, its Subsidiaries or its management
Global Iron	Global Iron Limited
Group	The Company, together with its consolidated subsidiaries
HAH AS	Hemla Africa Holding AS
HEPCO	Hemla E&P Congo S.A.
ICSID	The International Centre for the Settlement of Investment Disputes
IFRS	International Financial Reporting Standards
Information Memorandum	This Information Memorandum dated 29 March 2019
Issuer Sponsored Sub-register	A sub-register of the Company's Share Register administrated by

	Computershare Investor Services Pty Ltd, which constitutes the Company's share register
LIBOR	London Interbank Offered Rate
NOK	Norwegian Kroner, the lawful currency in Norway
NOR	NOR Energy AS
Norwegian Securities Trading Act	The Norwegian Securities Trading Act of 29 June 2007 "Verdipapirhandelloven"
NSX	The National Stock Exchange of Australia
Oslo Axess	A regulated market place operated by Oslo Børs ASA
Oslo Stock Exchange	Oslo Børs ASA
Petromal	Petromal – Sole Proprietorship LLC
PetroNor	PetroNor E&P Ltd
PetroNor Group	PetroNor E&P Ltd, together with its consolidated subsidiaries
PetroNor Warrants	The 155,466,446 warrants to be allocated to NOR in connection with the Transaction
PetroNor Warrants Vesting Event	(x) a signed acquisition/farm-in agreement for a gas asset in Nigeria, and (y) a signed and legally binding gas offtake agreement relating to the gas from such asset, both agreements on commercially acceptable terms approved by the Board of Directors
Petrosen	Société des Pétroles du Sénégal, the national oil company of Senegal
Prestamex	Prestamex Group Inc.
Record Date	26 April 2019, as further described in Section 4.4 "Consideration"
RFA	Requests for Arbitration
ROP	The Rufisque Offshore Profond block
Shares	The issued and outstanding shares in the Company as of the date of this Information Memorandum
SOSP	The Senegal Offshore Sud Profond block
The Gambia	The Republic of The Gambia
Transaction	The contemplated acquisition of 100% of the shares in PetroNor by the Company
UK	The United Kingdom
USD	United States Dollars, the lawful currency in the United States
U.S. Securities Act	The Securities Act of 1933, as amended
VPS	Verdipapirsentralen (Norwegian Central Securities Depository), which organises the Norwegian paperless securities registration system and where the Offer Shares will be registered
VPS Registrar	DNB Bank ASA

12.2 Glossary of terms

AAPG	The American Association of Petroleum Geologists
API	A measure of how heavy or light a petroleum liquid is compared to water
bcm	Billion cubic meters
2D seismic	Powerful echo sounders that receive sound reflected from the underground along straight lines.
3D seismic	As 2D seismic, but here the sound is captured in a net of receivers, enabling the construction of a three-dimensional picture of the underground. Smaller oil traps can more often than not be mapped only with the use of 3D seismic
E&P	Exploration and production
Farm-in/Farm-out	Acquire or to dispose of an oil interest to a third party

GST	Goods and services tax
HSE	Health, safety and environmental
MMstb	Million barrels of oil
OPEC	Organization of Petroleum Exporting Countries
PetroNor shares	The issued and outstanding shares in PetroNor as of the date of this Information Memorandum
PRMS	The Petroleum Resources Management System, issued by SPE, AAPG, WPC and SPEE in March 2007
Prospective resources	Estimated volumes associated with undiscovered accumulations. These represent quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from oil and gas deposits identified on the basis of indirect evidence but which have not yet been drilled. This class represents a higher risk than contingent resources since the risk of discovery is also added.
PSCs	Production Sharing Contracts
SPE	The Society of Petroleum Engineers
SPEE	The Society of Petroleum Evaluation Engineers
TVDSS	True Vertical Depth Sub Sea level
WPC	The World Petroleum Council

APPENDIX A:

COMPETENT PERSONS REPORT (CPR) PREPARED BY AGR PETROLEUM SERVICES AS DATED 30 OCTOBER 2018 WITH VOLUMES AS OF 1 JANUARY 2018, ADJUSTED FOR ACTUAL PRODUCTION DURING 2018

AGR Petroleum Services AS

Reservoir Management Division

Oslo

PNGF Sud / PNGF Bis (Congo Brazzaville) - CPR
Final

For Petronor E & P
October 2018

AGR Petroleum Services Technical Report

PNGF Sud / PNGF Bis (Congo Brazzaville) - CPR
Final

Approval			
	Name	*Position*	*Date*
Prepared by:	Anna-Lena Hellman John Erick Battié Jafar Aali Birger Heidenstrøm Marte Herud Urdahl Wiggo Moen	Project Manager Chief Geoscientist Advisor Petrophysicist Principal Reservoir Eng. B.H. Senior Reservoir Eng. Advisor Facilities Eng.	30.10.2018
Reviewed and Accepted by:	Gudmund Olsen	Advisor Reservoir Engineering	30.10.2018

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2	30.10.2018	Final	

Qualifications

AGR is an independent consultancy specializing in amongst others petroleum reservoir evaluation and economic analysis. Except for the provision of professional services on a fee basis, AGR does not have a commercial arrangement with any other person or company involved in the interests that are the subject of this report.

The report was managed by Mahmood Akbar (MSc in Petroleum Engineering), AGR Advisor Reservoir Engineering. Mr. Akbar, a Reservoir Engineer, has 25+ years of experience, and is an expert on reserves and resource reporting. The evaluation was reviewed and signed off by Morten Heir (MSc in Petroleum Engineering and MBA), AGR Vice President Reservoir Management. Mr. Heir, a Petroleum Engineer, has 25+ years of international experience, including the North Sea. AGR has conducted valuations for many energy companies and financial institutions.

Evaluation Standard

In certification of contingent resources and reserves, AGR has applied the standard petroleum engineering techniques. This certification is based on the joint definitions of the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers; Petroleum Resources Management System (SPE PRMS) from 2007 and 2011.

Basis of Opinion

The evaluation presented in this report reflects our informed judgment based on accepted standards of professional investigation, but is subject to generally recognized uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

Disclaimer

This report relates specifically and solely to the subject petroleum licence interests and is conditional upon the assumptions made therein. This report must therefore be read in its entirety. This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry, in particular the 2007/2011 SPE PRMS. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, these are also subject to uncertainties inherent in the application of judgmental factors in interpreting such information. AGR Petroleum Services AS shall have no liability arising out of, or related to, the use of the report.

Executive Summary

AGR has been contracted by NOR Energy AS to carry out an independent evaluation of four producing fields in licence PNGF Sud and one discovery in the neighbouring licence PNGF Bis in Congo Brazzaville.

Hereinafter AGR is referring to Petronor, (Petronor E&P owned by NOR Energy and Petromal) and Petronor's interest in the licence. Petronor has a stake in PNGF Sud, but is still not part of the PNGF Bis ownership.

Petronor interest in PNGF Sud - 14.85%

Petronor interest in PNGF Bis (contingent to decision to enter into the licence) - 20.79%

There is production in PNGF Sud from four structures with one to three vertically stacked reservoirs and a total of some 54 active wells.

In the PNGF Bis there are two discoveries, one of which is proposed for a tie-back and long production test in 2019.

Perenco is the Operator since 1.1.2017 for both licences and has since taking the operatorship increased total production from ca 15 kbopd to 22 kbopd by relatively simple well work such as repairing and increasing size of ESP's, re-perforations and stimulations.

The evaluation covers the Tchibouela Main/East, Tchendo, Tchibeli and Litanzi fields in PNGF Sud. In PNGF Bis the evaluation covers the Loussima SW discovery. The AGR evaluation includes categorisation of proved (1P), proved + probable (2P) and proved + probable + possible (3P) reserves, as well as contingent resources (1C, 2C and 3C). The reporting is according to the SPE PRMS (Petroleum Resources Management System) with effective date January 1st, 2018.

This evaluation is based on data provided by Petronor. AGR has had access to a detailed production data per structure / reservoir and well in a spreadsheet, older Petrel static and dynamic models, seismic data, economic model and a summary report from Petronor on the asset. Further documentation from both licence meetings from 2014-2018 and older reports from the former operator Total. AGR has checked whether the methods used are according to sound engineering practice, whether the results are reasonable and for consistency with the definitions of reserves. AGR has checked base case volumes and performed sensitivities in the models where relevant to test the robustness and uncertainty range of in-place volumes, future production and resources. AGR has considered and discussed the major uncertainties and risks.

Production profiles for low, base and high cases are presented and tested for economic cut-off in order to define 1P, 2P and 3P reserves. Economic assumptions used by AGR have been agreed with Petronor. Contingent resources are presented with volumes for 1C, 2C and 3C. Production profiles are given for 2C resources, only total numbers and no profile as such, for 1C and 3C.

Asset Overview PNGF Sud
A location map with the assets subject for this report are shown and summarized in the figure and table below.

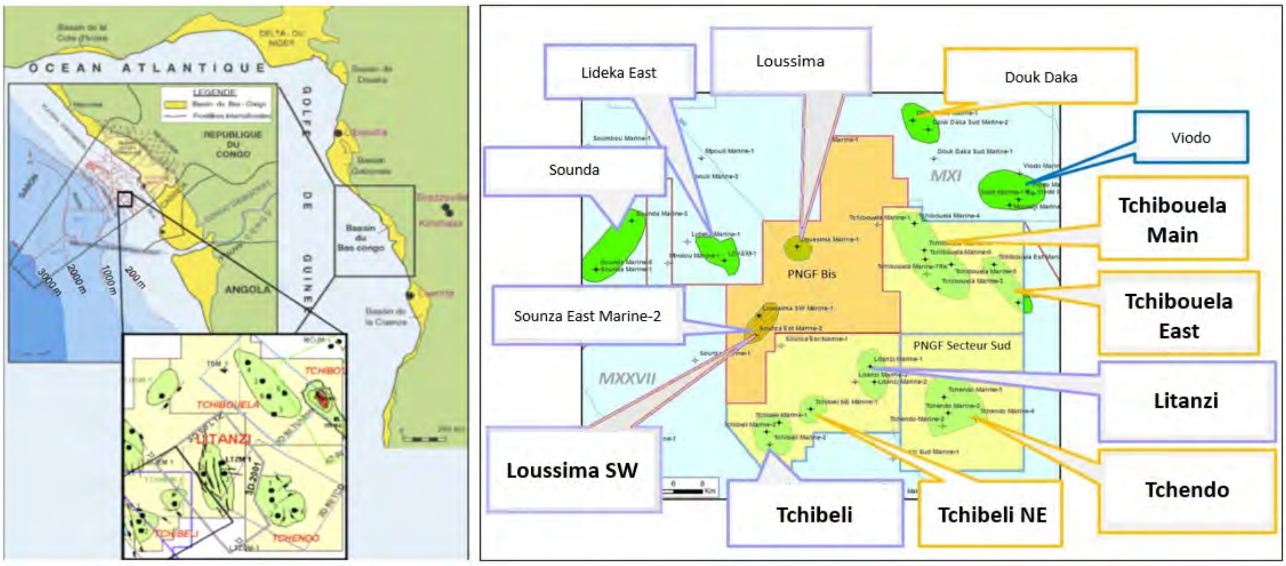

Figure 1 licence PNGF Sud and PNGF Bis Location map and fields/discoveries
Fields and discoveries in PNGF Sud and PNGF Bis are highlighted.
Source: Perenco

Table 1 PNGF Sud assets

Asset	Reservoir	Installation	Status	Resource category (SPE-PRMS)
Tchibouela Main	Turonian/ Cenomanian	Processing platform and well head platforms	On Production	Reserves
Tchendo	Senonian/Turonian/ Cenomanian	Well head platform and subsea wells	On Production	Reserves
Tchibeli	Albian	Well head platform	On Production	Reserves
Litenzi	Albian	Well head platform	On Production	Reserves
Tchibouela Main - Infill drilling	Turonian/ Cenomanian	Existing installations	Development unclarified	Contingent Resources
Tchendo - Infill drilling	Senonian/Turonian/ Cenomanian	Existing installations	Development unclarified	Contingent Resources
Tchibeli - Infill drilling	Albian	Existing installations	Development unclarified	Contingent Resources
Litanzi - Infill drilling	Albian	Existing installations	Development unclarified	Contingent Resources

Some more details on each asset follow below.

Tchibouela Field
Tchibouela is an oil field with two separate structures, Tchibouela Main and Tchibouela East. The water depth is 80 m in the area. Tchibouela Main was discovered in 1983 and Tchibouela East in 1985.

<u>Tchibouela Main</u> consists of three disconnected reservoirs: Senonian, Turonian and Cenomanian with reservoir depths ranging from 300 to 1000 mTVDSS. The structure is a dome formed anticline and the reservoir quality is good but varying. The main reservoirs in Turonian and Cenomanain contain oil of 27 degAPI with low GOR. The youngest reservoir, Senonian contains gas with an oil rim below.

Tchibouela Main is producing from 21 active oil producers. The field came on stream in 1987, had a peak production in 1995 and is now on decline. The current water cut is high. Cenomanian is an excellent reservoir with a strong aquifer and has a high current recovery. The Turonian has more varying reservoir properties, also here the pressure is maintained by natural water influx and one water injector. Both reservoirs are currently on decline. There are two gas producers in Senonian providing gas for gas lift and electricity production.

The field has been subject to extensive well workovers; re-perforations and ESP repair/replace, to maintain and improve production from the current producers, and the current Operator Perenco has speeded up this work. The Operator has plans to continuously perform well workovers and increase production from 8 000 bpd end 2016 to 12 000 bpd in 2018.The existing producers (including well workovers) are included in the reserves.

There is potential for infill drilling in Cenomanian and significant potential in the Turonian. There are currently no decisions taken for infill drilling in the licence and production from infill wells are classified as contingent resources ("Development unclarified")

Tchibouela East is a similar smaller dome structure as Tchibouela Main, with Turonain and Cenomanian reservoir levels. The field started production in 1998 with 6 oil producers. The Cenomanian reservoir has had water breaktrough. T0 and T2 of the Turonian reservoir have not been put into production due to gas cap within a thin reservoir, but T1 has been produced. The field closed mid 2016 due to blocking of an export pipe. There is still potential in this field but no plans for re-startup is presented by the Operator. However, Perenco has forecasted some 2.5 MMbbl in their 2P estimate.

Tchendo Field

Tchendo is an oil field with production from three separate reservoir levels, Senonian, Turonian and Cenomanian with reservoir depths from 450 to 750 mTVDSS. The structure is a gentle dome structure similar to Tchibouela and with similar reservoir qualities. The water depth is 95 m. Tchendo was discovered by exploration well TCDM1 in 1979 and came on stream in 1991. Peak production was reached in 1993 and the field has since then been on decline. In total 29 producers and eight injectors have been drilled on the field, of which 16 wells are still producing. Seven well are producing from the Senonian, which holds a large STOIIP, but with low permeability and low recovery so far. Nine wells are currently producing in Turonian supported by water injection. Water cut is high in Turonian, but still low in Senonian. There has been no production from Cenomanian since 2009.

The number of producers have increased since Perenco took over operatorship and there are plans for more well workovers in 2018 and 2019. The production from existing producers (including well workovers) are included in the reserves.

There is potential for some infill drilling in Turonian. There are currently no decisions taken for infill drilling in the licence and production from infill wells are classified as contingent resources ("Development unclarified").

The recovery from the Senonian is low and the potential for redevelopment with horizontal producers, possibly with stimulation (fracking), have been flagged by Perenco and Petronor. Redevelopment of Senonian is classified as contingent resources.

Tchibeli Field

Tchibeli is an oil field producing from two reservoir levels in Sendji Fm of Albian age. The upper reservoir is a mix of carbonate and clastics, while the lower is a carbonate reservoir. The reservoir depth is 2000 mTVDSS and the water depth is 100 m. The four-way closure formed as a turtle-back structure cut by several faults. The reservoir quality is fair to good. The field was discovered in 1986 and came on stream in 2000. Peak production was reached two months after start-up and the field has since been on decline. Three oil producers are supported by two water injectors and artifical lift by ESP is important for recovery.

This field is the only one in the licence exporting to the Nkossa FPSO. A new export pipeline will be installed from Tchibeli to Tcibouela in 2018. This will make Tchibeli independent of Nkossa, debottleneck capacity and yield a significant tariff savings.

The production from existing producers (including well work overs and de-bottlenecking) are included in the reserves.

There is potential for some infill drilling in Albian. No infill drilling decision have yet been made in the license and production from infill drilling is therefore classified as contingent resources ("Development unclarified").

Tchibeli NE is a smaller Albian discovery north-east of Tchibeli, which is undeveloped. No information about in-place volumes nor plans for development has been presented by the Operator.

Litanzi Field
Litanzi is an oil field producing from Albian Sendji Fm carbonate reservoir. The structure is located north-east of Tchibeli, consists of a relatively thin reservoir zone cut by abundant faults dipping towards the west. The reservoir depth is at 1600 mTVDSS and the water depth is 100 m. Litanzi was discovered in 1990 and started production from one oil producer drilled from the Tchendo platform in 2000. The production is supported by one water injector and the production has been stable and high. Since mid 2016 the oil production has been increasing, and the water-cut has stabilized.

There is potential for at least one infill well, preferably in the western down-faulted area. No infill drilling decision have yet been made in the license and production from infill drilling is therefore classified as contingent resources ("Development unclarified ")

Reserves and Contingent Resources PNGF Sud
AGR has verified the reserves and contingent resources as shown in the tables below. Petronor interest in PNGF Sud is 14.85%

Table 2 Gross reserves as of 1.1.2018 verified by AGR

Asset	1P	2P	3P
	MMboe	MMboe	MMboe
Tchibouela	44.11	56.30	67.39
Tchendo	11.29	22.14	26.64
Tchibeli	8.86	12.33	15.27
Litanzi	2.54	4.10	5.56
Total	**66.80**	**94.87**	**114.86**

Table 3 PNGF Sud Gross contingent resources as of 1.1.2018 verified by AGR

Asset	1C	2C	3C
	MMboe	MMboe	MMboe
Tchibouela - Infill drilling	6.6	12.9	22.2
Tchendo - Infill drilling	6.0	11.5	19.0
Tchibeli - Infill drilling	4.1	7.1	12.0
Litenzi - Infill drilling	1.5	3.0	5.6
Total	**18.3**	**34.4**	**58.8**

The total 1P, 2P and 3P are the arithmetic sum of the respective reserves. 1C, 2C and 3C are the arithmetic sum of the respective contingent resources. This is compliant with the SPE-PRMS guidelines.

The production profiles (for reserves estimation) have been checked for economic cut-off.

Asset Overview PNGF Bis

Table 4 PNGF Bis assets

Asset	Reservoir	Installation	Status	Resource category (SPE-PRMS)
Loussima SW - Test production	Vandji Fm	Well head platform	Development pending	Contingent Resources
Loussima SW - Full development	Vandji Fm	Unclarified	Development Unclarified	Contingent Resources

Three exploration wells have been drilled on the licence, (Figure 3.1 and Figure 3.2). A discovery in pre-salt Vandji Fm was made in well LUSM-1 on Luossima 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 was detected in one of the wells in the Albian post-salt Sendji Fm, (analogue to Tcibeli/Litanzi reservoirs in PNGF Sud). The Sendji interval was not production tested .

The depth to the Vandji reservoir is 3250 mTVDSS, to Sendji around 1940 mVDSS and the water depth in the area is 110 m.

Production tests on the Loussima SW in the well LUSOM-1 and in the SUEM-2 well have been promising.

Perenco has proposed a project with test/early production on Loussima SW. The project will be utilizing a used jack-up rig which will be converted and prepared for early production from one well. Tie-in to Tchibouela TAF1 through a 11 km long pipeline is planned.

A full field development is foreseen based on a positive outcome of the planned long term test.

Reserves and Contingent Resources PNGF Bis

AGR has verified the contingent resources as shown in the tables below. Petronor interest in PNGF Bis (contingent to decision to enter into the licence) will be 20.79% via a 28% interest to Hemla E&P Congo (HEPCO).

Table 5 PNGF Bis Gross contingent Resources as of 1.1.2018 verified by AGR.

	Oil, MMbbl		
Gross	**1C**	**2C**	**3C**
Loussima SW - Test production	0.4	1.9	3.8
Loussima SW - Full development	22	27	32

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1 Introduction

Scope of Work
AGR has been contracted by NOR Energy AS to carry out an independent evaluation of four producing fields in licence PNGF Sud and one discovery in the neighbouring licence PNGF Bis in Congo Brazzaville.

Hereinafter AGR is referring to Petronor, (Petronor E&P owned by NOR Energy and Petromal) and Petronor's interest in the licence. Petronor has a stake in PNGF Sud, but is still not part of the PNGF Bis ownership.

Petronor interest in PNGF Sud is 14.79% via a 20% interest in PNGF Sud to Hemla E&P Congo (HEPCO).

Petronor interest in PNGF Bis (contingent to decision to enter into the licence) will be 20.79% via a 28% interest in PNGF Bis to Hemla E&P Congo (HEPCO).

There is production in PNGF Sud from four structures with one to three vertically stacked reservoirs and a total of some 54 active wells. In the PNGF Bis there are two discoveries, one of which is proposed for a tie-back and long term production test in 2019.

Perenco is the Operator since 1.1.2017 for both licences and has since becoming operator increased total production from ca 15 kbopd to 22 kbopd by relatively simple well work such as repairing and increasing size of ESP's, re-perforations and stimulations.

The evaluation covers the Tchibouela Main/East, Tchendo, Tchibeli and Litanzo fields in PNGF Sud. In PNGF Bis the evlauation covers the Loussima SW discovery. The AGR evaluation includes categorisation of proved (1P), proved + probable (2P) and proved + probable + possible (3P) reserves, as well as contingent resources (1C, 2C and 3C). The reporting is according to the SPE PRMS (Petroleum Resources Management System) with effective date January 1st, 2018.

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Production profiles for low, base and high cases are presented and tested for economic cut-off in order to define 1P, 2P and 3P reserves. Economic assumptions used by AGR have been agreed with Petronor. Contingent resources are presented with volumes for 1C, 2C and 3C. Production profiles are given for 2C resources, only total numbers and no profile as such, for 1C and 3C.

Methodology
AGR has conducted this evaluation based on the information and data provided by Petronor. In general the methodology applied in this evaluation can be summarised as follows:

- Review of the available data, interpretations and resulting models and reports that have been made available to AGR.
- The critical parameters were checked in terms of origin of the data, the interpretation and application thereof.
- Review of the methodologies applied to generate production forecasts and reserve estimates.
- Review of uncertainty analyses.
- Review of the costs
- Determination of economic cut-offs with resulting reserves.
- Classification of reserves and contingent resources according to the Petroleum Resources Management System (SPE/WPC/AAPG/SPEE).

2 PNGF Sud

2.1 Asset Overview

PNGF Secteour Sud licence is located offshore Congo Brazzaville, 25 km off the coast of Pointe Noire.

A location map with the assets subject for PNGF Sud in this report are shown in Figure 2.1 and summarized in Table 2.1. The location of the producing fields in the licence in relation to PNGF Bis and surrounding producing fields are shown in Figure 2.2.

Perenco is the current operator of the licence and took over the operatorship from the former operator Total in 2016. Petronor has an interest of 14.85% in PNGF Sud.

The PNGF Bis licence is located to the northwest of PNGF Secteour Sud.

Figure 2.1 Location of the PNGF Sud licence

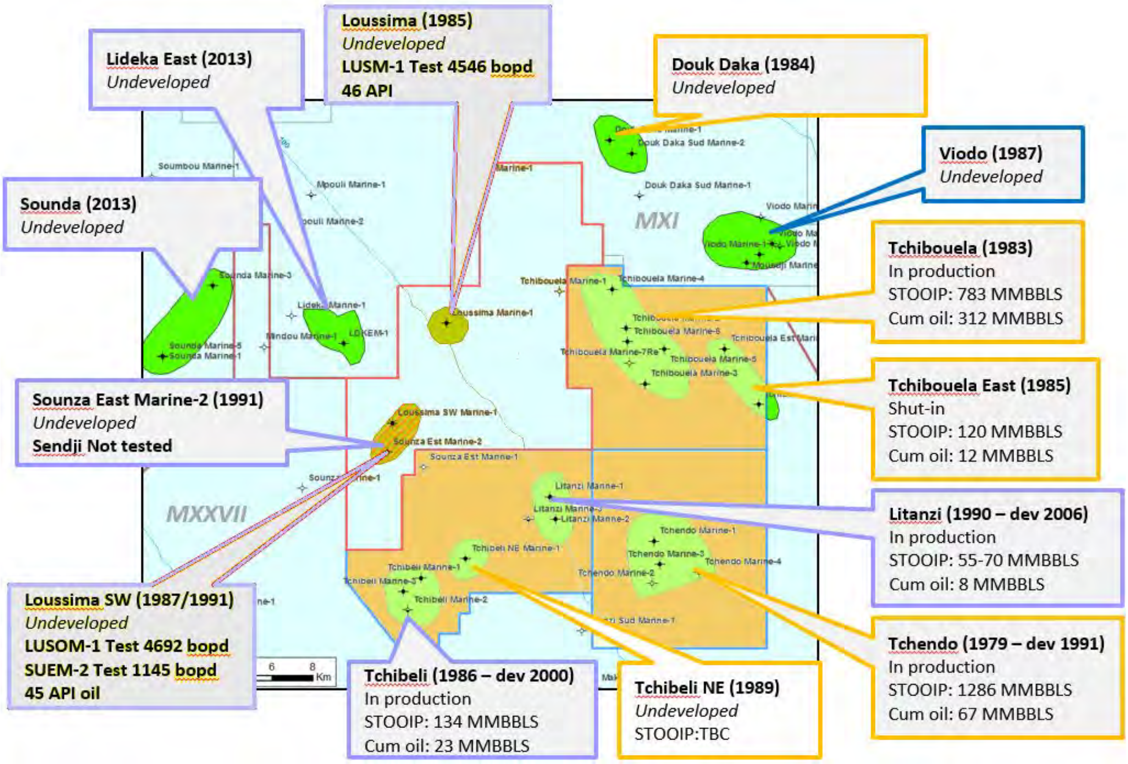

Figure 2.2 PNGF Sud licence with surrounding producing fields and discoveries
Source: Perenco

Table 2.1 PNGF Sud assets

Asset	Reservoir	Installation	Status	Resource category (SPE-PRMS)
Tchibouela Main	Turonian/Cenomanian	Processing platform and well head platforms	On Production	Reserves
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Some more details on each asset follow below.

Tchibouela Field
Tchibouela is an oil field with two separate structures, Tchibouela Main and Tchibouela East. The water depth is 80 m in the area. Tchibouela Main was discovered in 1983 and Tchibouela East in 1985.

Tchibouela Main consists of three disconnected reservoirs: Senonian, Turonian and Cenomanian with reservoir depths ranging from 300 to 1000 mTVDSS. The structure is a dome formed anticline and the reservoir quality is good but varying. The main reservoirs in Turonian and Cenomanain contain oil of 27 degAPI with low GOR. The youngest reservoir, Senonian contains gas with an oil rim below.

Tchibouela Main is producing from 21 active oil producers. The field came on stream in 1987, had a peak production in 1995 and is now on decline. The current water cut is high. Cenomanian is an excellent reservoir with a strong aquifer and has a high current recovery. The Turonian has more varying reservoir properties, also here the pressure is maintained by natural water influx and one water injector. Both reservoirs are currently on decline. There are two gas producers in Senonian providing gas for gas lift and electricity production.

The field has been subject to extensive well workovers; re-perforations and ESP repair/replace, to maintain and improve production from the current producers, and the current Operator Perenco has speeded up this work. The Operator has plans to continuously perform well workovers and the production from existing producers (including well workovers) are included in the reserves.

There is potential for infill drilling in Cenomanian and significant potential in the Turonian. There are currently no decisions taken for infill drilling in the licence and production from infill wells are classified as contingent resources ("Development unclarified")

Tchibouela East is a similar smaller dome structure as Tchibouela Main, with Turonain and Cenomanian reservoir levels. The field started production in 1998 with 6 oil producers. The Cenomanian reservoir has had water breaktrough. T0 and T2 of the Turonian reservoir have not been put into production due to gas cap within a thin reservoir, but T1 has been produced. The field closed mid 2016 due to blocking of an export pipe. There is still potential in this field but no plans for re-startup is presented by the Operator. However, Perenco has forecasted 2.5 MMbbl in their 2P estimate, but that is not reviewed herein.

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The production from existing producers (including well work overs and de-bottlenecking) are included in the reserves.

There is potential for some infill drilling in Albian. No infill drilling decision have yet been made in the license and production from infill drilling is therefore classified as contingent resources ("Development unclarified").

Tchibeli NE is a smaller Albian discovery north-east of Tchibeli, which is undeveloped. No information about in-place volumes nor plans for development has been presented by the Operator.

Litanzi Field
Litanzi is an oil field producing from Albian Sendji Fm carbonate reservoir. The structure is located north-east of Tchibeli, consists of a relatively thin reservoir zone cut by abundant faults dipping towards the west. The reservoir depth is at 1600 mTVDSS and the water depth is 100 m. Litanzi was discovered in 1990 and started production from one oil producer drilled from the Tchendo platform in 2000. The production is supported by one water injector and the production has been stable and high. Since mid 2016 the oil production has been increasing, and the water-cut has stabilized.

There is potential for at least one infill well, preferably in the western down-faulted area. No infill drilling decision have yet been made in the license and production from infill drilling is therefore classified as contingent resources ("Development unclarified ")

Geological Setting

The licence is located in the Congo basin which is part of the Aptian salt basins of equatorial west Africa. The region is passive margin pull-apart (South America/Africa) basin. The petroleum system consists of Lower Cretaceous to Tertiary source and reservoir rocks. The evaporite salt layer of Aptian age separates the distinct pre- and post-salt sedimentary sequences. The producing reservoirs in PNGF Sud are situated in the post-salt sequence. All the post-salt sediments are marine in origin, deposited during the drift phase of the basin formation.

The Sendji Carbonate (Aptian-Albian) is the most important reservoir in Congo and consists of shallow marine, high-energy oolitic/oncolytic shoal deposits. The Tchibeli and Litanzi Fields produce from these turtle-back reservoirs.

The continental to marginal littoral Tchala Formation Sandstone (Cenomanian) is the main reservoir in the Tchibouela and Tchendo fields. This formation is syn-sedimentary to the listric faulting associated with the underlying turtle-back structures, filling in the created half grabens.

Additionally, the transgressive sandstone grading to shelly limestone called Loango Dolomite (Turonian), produces oil in Tchibouela East and Tchendo fields.

Overlying these sediments are the Emeraude Silt (Senonian), a fine-grained, poorly-consolidated carbonate-rich silty sandstone.

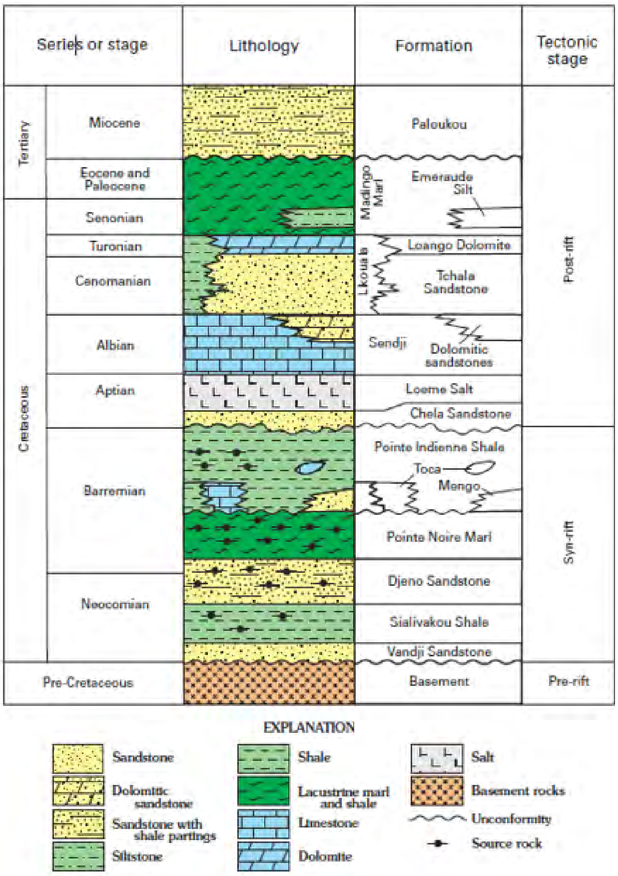


Figure 2.3 Generalized stratigraphic column for the Congo Basin
Source: USGS

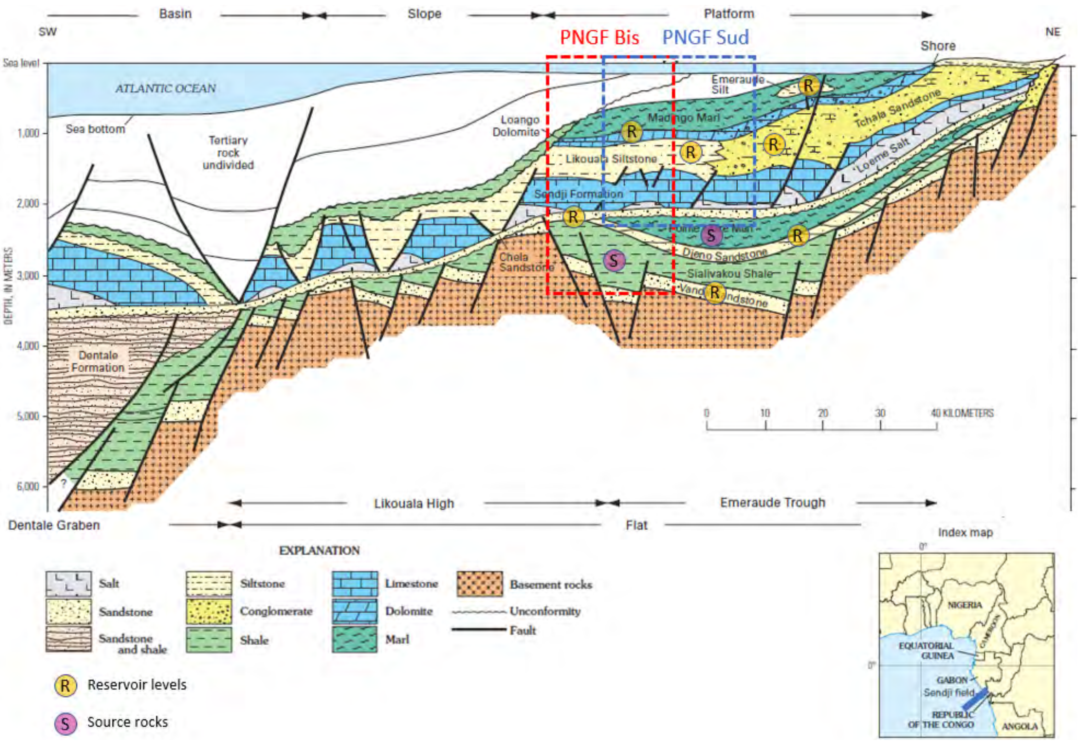


Figure 2.4 Congo Basin Regional geological profile with petroleum system elements
Source: USGS/Perenco/Petronor

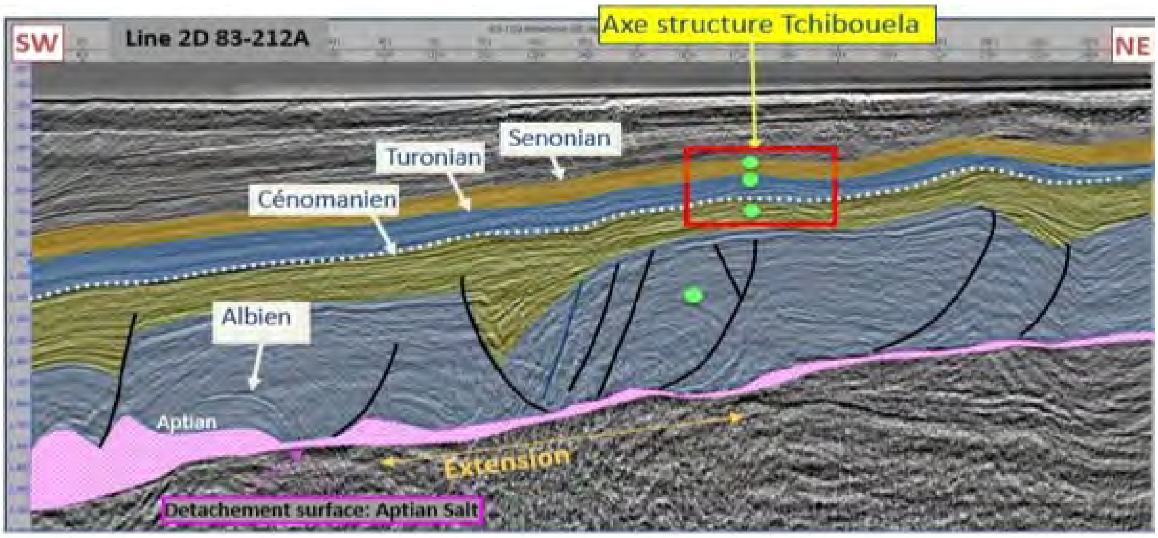


Figure 2.5 Generalized regional seismic section over the PNGF Sud/Bis licenses
Source: Perenco

Facilities Overview
The PNGF Sud is developed with seven steel jackets as drilling or processing centres. The outline of the facilities can be seen in Figure 2.6. The wells are tied back to each drilling centre. Gas is flared or sent to Yanga - Sendji field centre. The oil from Tchibouela/Tchendo/Litanzi is exported via the onshore Djeno terminal. The oil from Tchibeli is exported via the Nkossa FPSO.

As the platforms and subsea flowlines are ranging from more than 30 years to 10 years in operation, there could be various challenges with respect to the technical integrity status and the subsequent maintanance/ operation strategy and plans. The visual inspection performed by Hemla in 2016 do encompass several activities to be undertaken to prolong platform field life. AGR has seen that Perenco has initiated some related activities, but AGR is uncertain to the present status and would advise Petronor to be "hands on" in this respect.

If many new wells should be predicted, the availability of well slots should be focused.

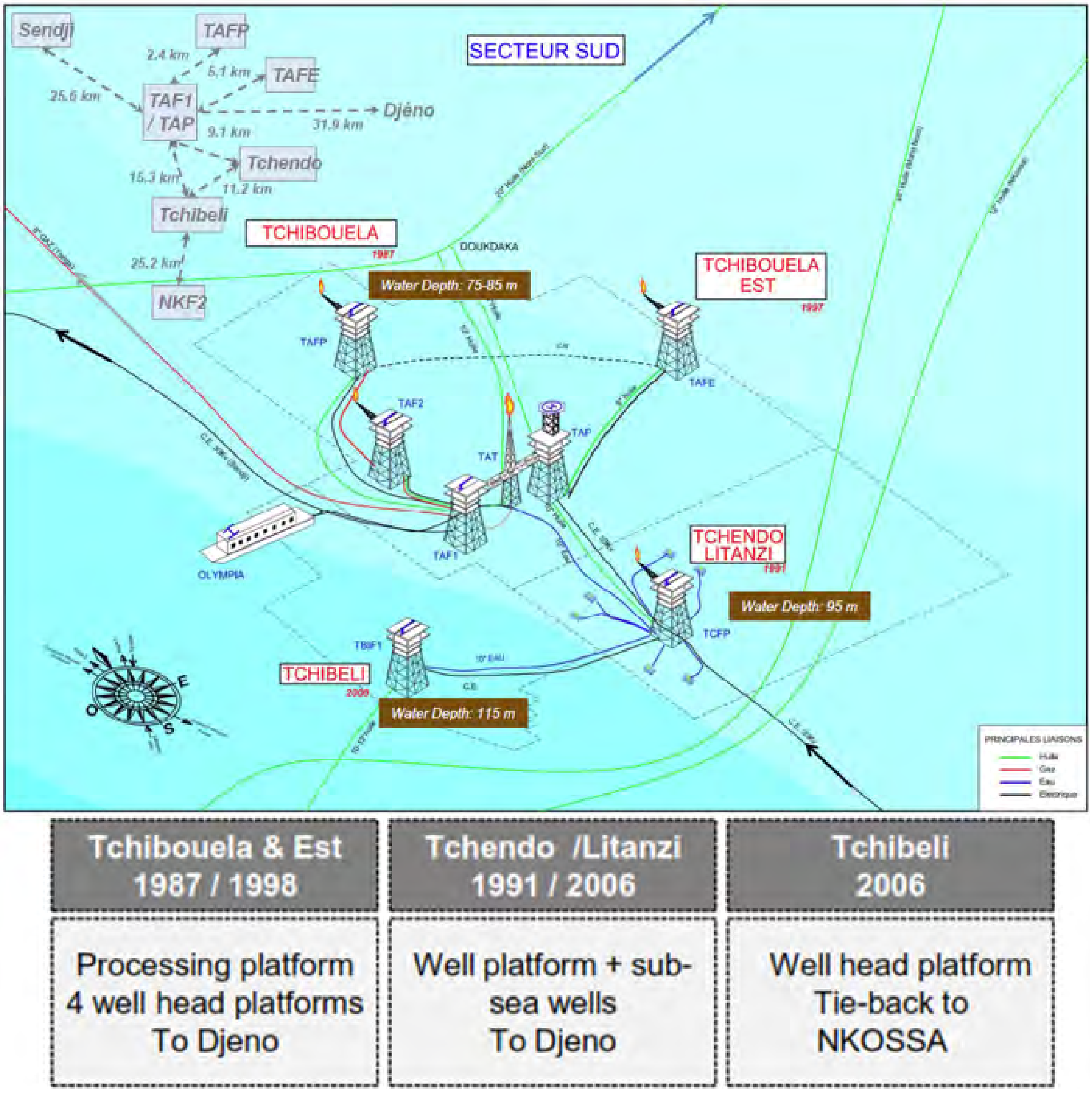


Figure 2.6 PNGF Sud facilities overview

2.2 Tchibouela Main/East

2.2.1 G&G

Geological Setting

A schematic crossection of the producing reservoir intervals together with the depth map of the Turonian T0 reservoir level of the Tchibouela Main field, (Figure 2.7), illustrates the dome structure. The field is appraised by nine exploration wells and together with the development wells from three drill centres the structure is well defined. Sendji Fm sandstone of Cenomanian age, Loango Fm of Turonian age comprise the major reservoir levels, while the younger Emeraude Silt Fm holds a gas accumulation with a thin oil zone.

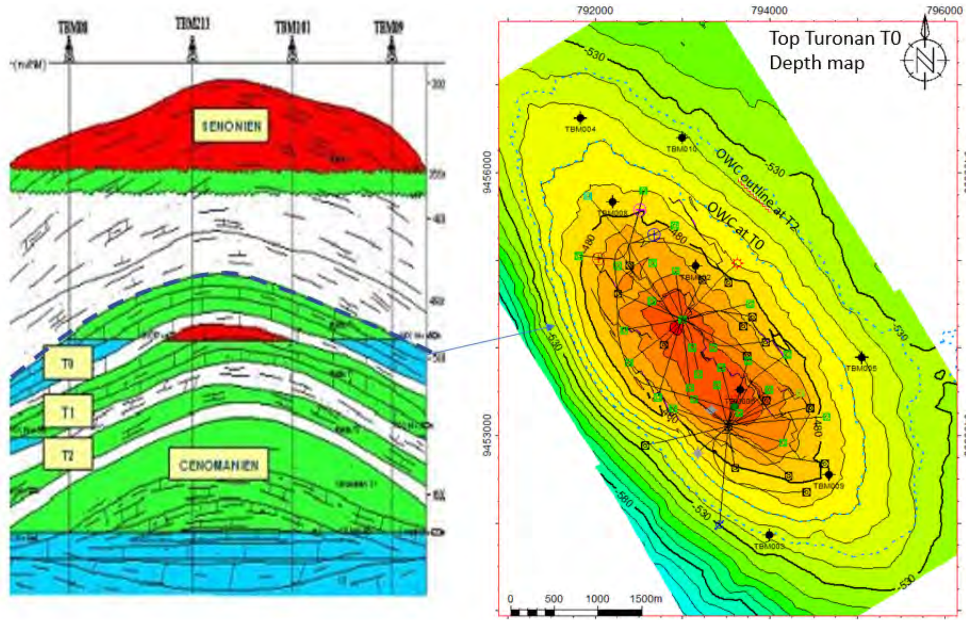


Figure 2.7 Tchibouela Main. Top T0 reservoir depth map and schematic crossection of reservoir levels

The smaller Tchibouela East field is illustrated correspondingly in Figure 2.8. The structure is similar to the Tchibouela Main a gentle dome structure consisting of several reservoir levels in Cenomanian and Turonian.

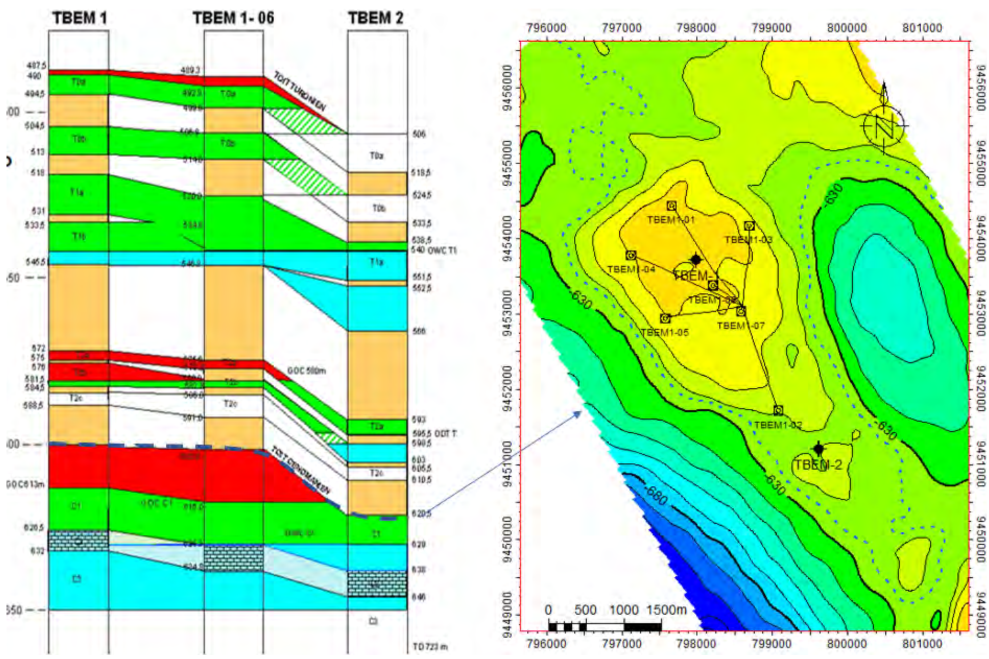


Figure 2.8 Tchibouela East. Top Cenomanian depth map and schematic crossection of the reservoir levels

The depositional environment for the Cenomanian / Turonian in this area grades from submarine with channel sandstones to shallow marine with clastic sedimentation alternating with shelf carbonates. The Cenomanian is a more homogeneous sandstone while the heterogeneity in Turonian is exemplified by the well correlation with depositional environment interpretation in Figure 2.9. In general in this area, the T2 level consists of calcareous sandstone, the T1 is a mixture of sand and limestone while the T0 consists mainly of limestone mixed with shaly silt.

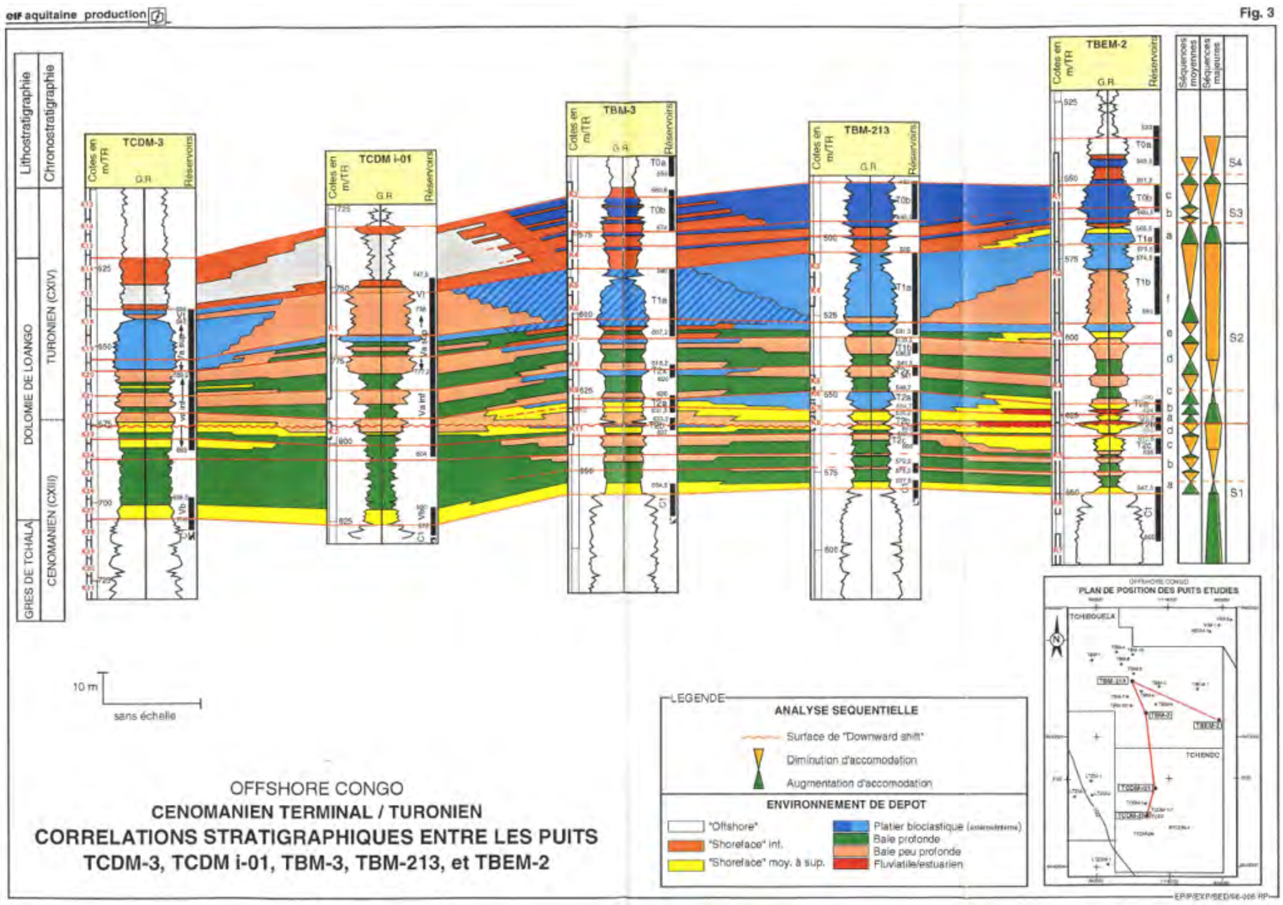


Figure 2.9 Lithostratigraphical correlation of the Turonian on Tchibouela Main/East
Source: Elf 1996

Reservoir properties
Reservoir properties in Tchibouela Main and Tchibouela East are summarized in Table 2.2 as reported in the data room documentation for Turonian and Cenomanian. Reservoir properties are not available for the Senonian.

AGR has reviewed the log data provided, including full set conventional well logs and petrophysical interpretation results for the Turonian and Cenomanian. It is worth mentioning that Senonian interval is not evaluated over the Tchibouela Main and Tchibouela East wells. In general quality of the petrophysical results and well logs is fair. However, porosity logs (specifically density/neutron logs) are severely affected by washouts. It seems density log is used for porosity model as such computed effective porosity is overestimated over the washout zones. It is worth mentioning that Senonian interval is not evaluated by AGR over the Tchibouela Main and Tchibouela East wells, and property values are taken from Perenco presentations.

Table 2.2 Reservoir parameters for the Tchibouela field

Field	Reservoir	Thickness (m)	net/gross	Porosity	Sw	Permeability (mD)
Tchibouela Main	Senonian	-	-	20	-	1-50
	Turonian T0	40	0.44	0.20	-	1 - 500

Field	Reservoir	Thickness (m)	net/gross	Porosity	Sw	Permeability (mD)
	Turonian T1	30	0.50	0.21	-	1 - 500
	Turonian T2	20	0.60	0.20 - 0.25	-	400 - 2000
	Cenomanian	30	0.90 - 1.00	0.26	0.25	>2000
Tchibouela East	Turonian T0		-	0.15	-	250
	Turonian T1		-	0.20	-	-
	Turonian T2		-	0.20	-	-
	Cenomanian		-	0.275	-	2500 - 10000

Seismic Data

The seismic data over the Tchibouela field (Figure 2.10) was acquired in 1986 and was merged with the 1996 survey for Tchibouela East in 2009. The merged survey was subsequently reprocessed with a prestack depth migration in 2013.

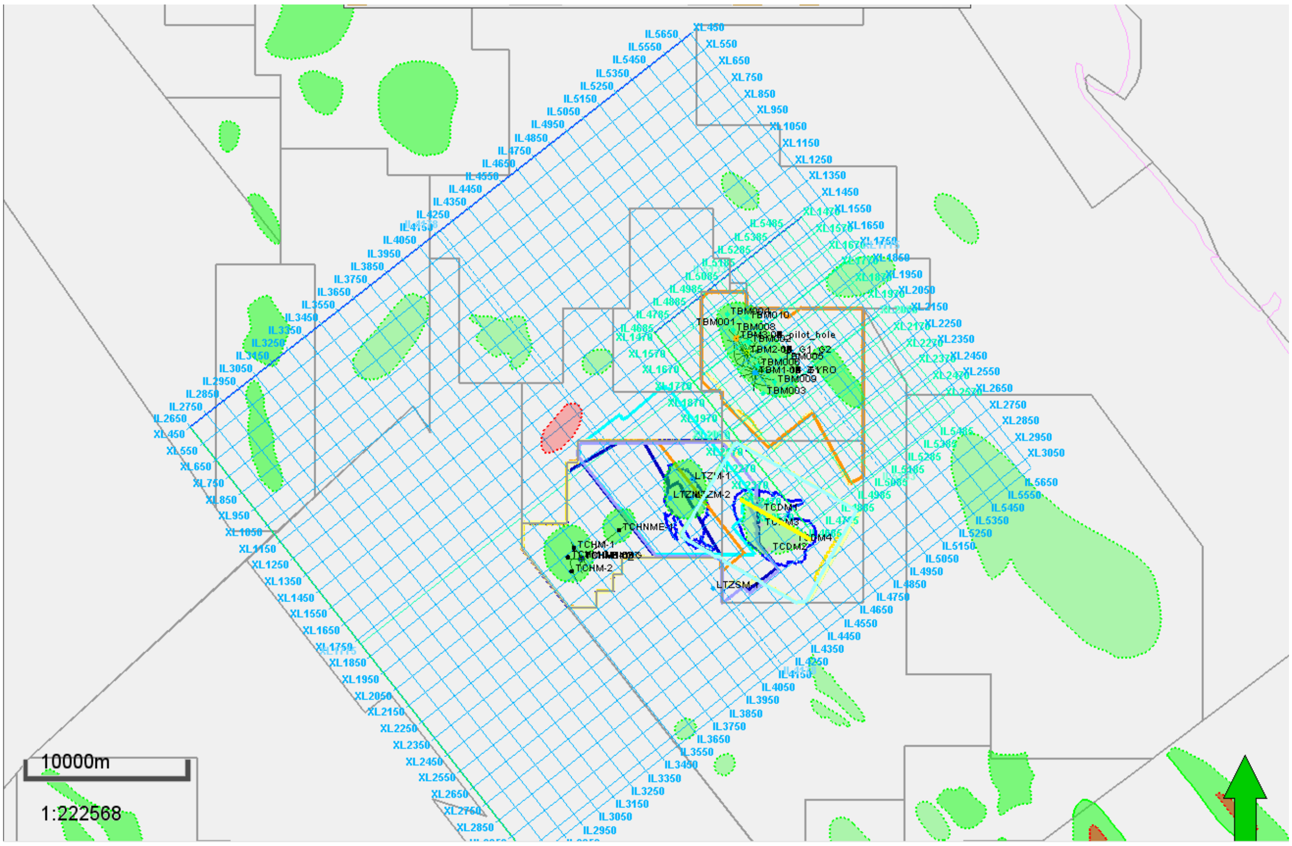


Figure 2.10 Tchibouela. Seismic coverage map

The data quality is good. The Tchibouela field is hampered by a shadow zone with a velocity sag/pull down beneath a large bright spot (Figure 2.11). Most of the production occurs within the shadow zone. Polarity is SEGY Normal, meaning a positive reflection for an increase in impedance.

There is no evidence of seismic well ties from the material supplied, though the original operator must have performed the task.

The seismic interpretation has the general form of the seismic over the east flank (Figure 2.11). Over the crest of the structure well depths must have been used to make the maps as it is not possible to make an interpretation. And the interpretation over the east flank does not match either the time or depth seismic in form.

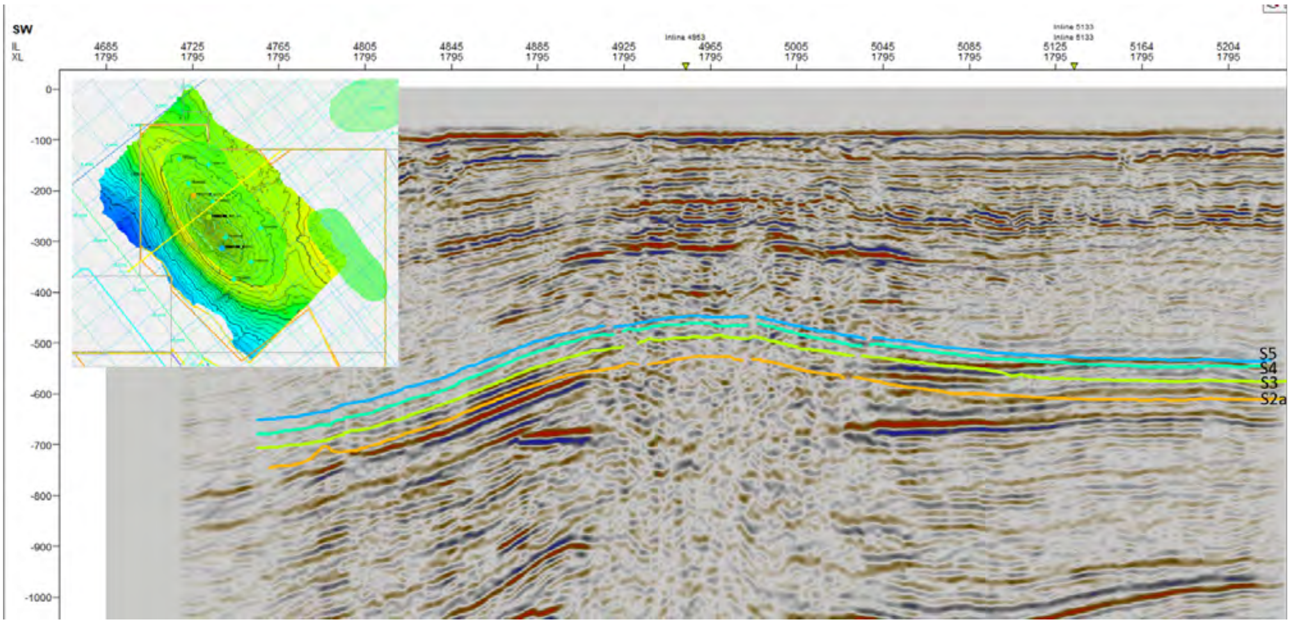


Figure 2.11 Tchibouela. 2013 seismic with interpretation and map.
The inserted depth structure is the S2a surface.

The seismic quality is the same over Tchibouela East as for Tchibouela (Figure 2.12). As with Tchibouela, Tchibouela East has a bright spot above along with sag/pull down effect along with gas chimneys. Note that the delivered Petrel projects contained no interpretation over Tchibouela East.

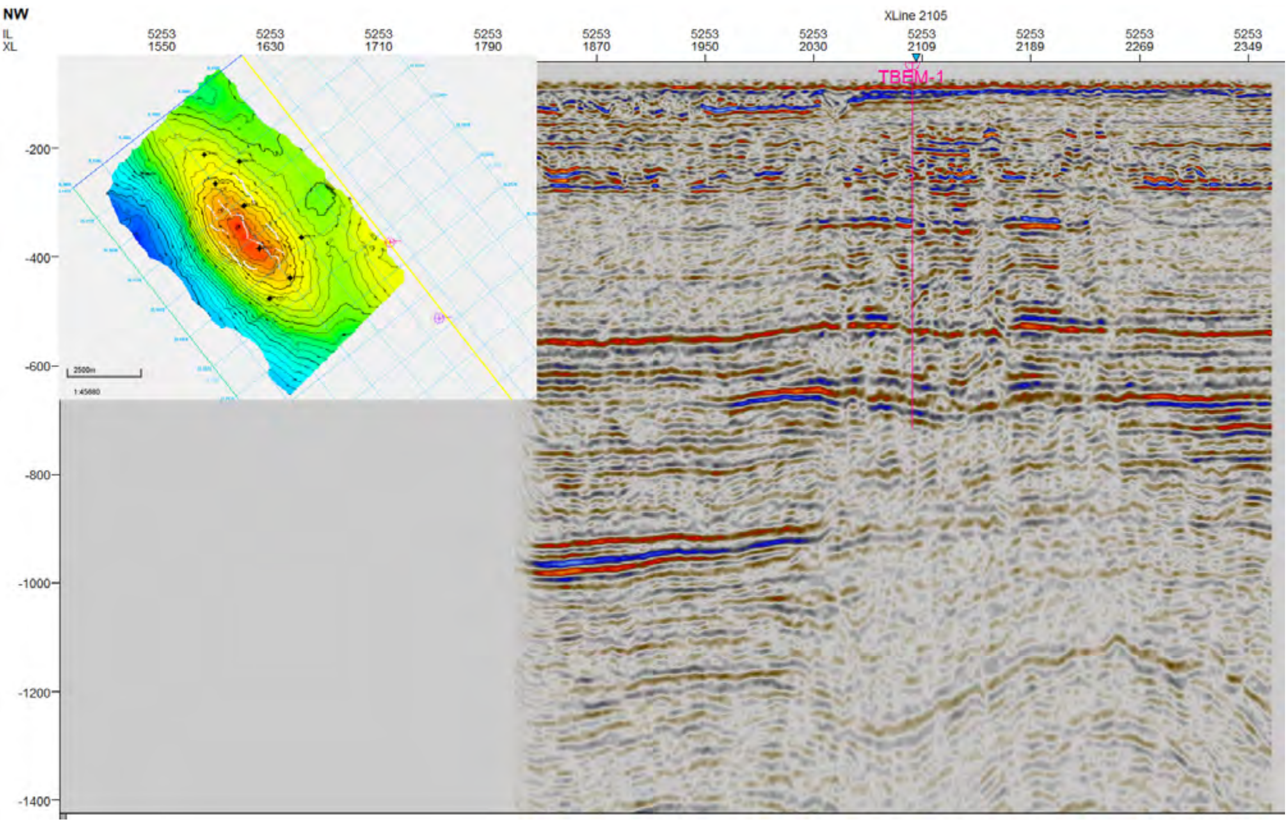


Figure 2.12 Seismic over Tchibouela East with structure map from Tchibouela.

Static Models
Perenco has not prioritized any update of static models in these fields yet. In the data room there is one static model in Petrel from Total, dated 2008, covering the Turonian T0, T1 and T2 for Tchibouela Main. There is no static model for Cenomanian on Tchibouela Main and the latest work seems to be the model documented in a report from Elf in 1998. AGR has observed that Total has built a static models over Albian, in 2006 for Tchibouela Main and in 2014 for Tchibouela East, but no further information was available.

The structural framework for the Turonian model consists of seismic depth maps of Top T0, T1 and T2 corrected to well tops. Perenco well tops from 2017 are included in Petrel and have minor adjustments from the Total 2008 tops. As mentioned above the model surfaces do not match the latest seismic. On the crest the well coverage is good, but an uncertainty remains on the flanks.

A facies model includes 6 facies types, where sandstone and limestone(compact) hold most the oil volumes. As illustrated in Figure 2.13 the volume fraction of sandstone decreases upwards and towards south west which is in line with the conceptual model. Facies, net/gross, porosity (PHIT) and water saturation (SWT) in three wells are plotted in Figure 2.14 to get an impression of how the logs compare to the model. First, AGR observed that there is no correlation between facies and net/gross. Total has used the total porosity system, but this methodology requires a well define net/gross. In this case there might be an overestimation of pore volume in the layers where net/gross is less than 1 when using the total system.

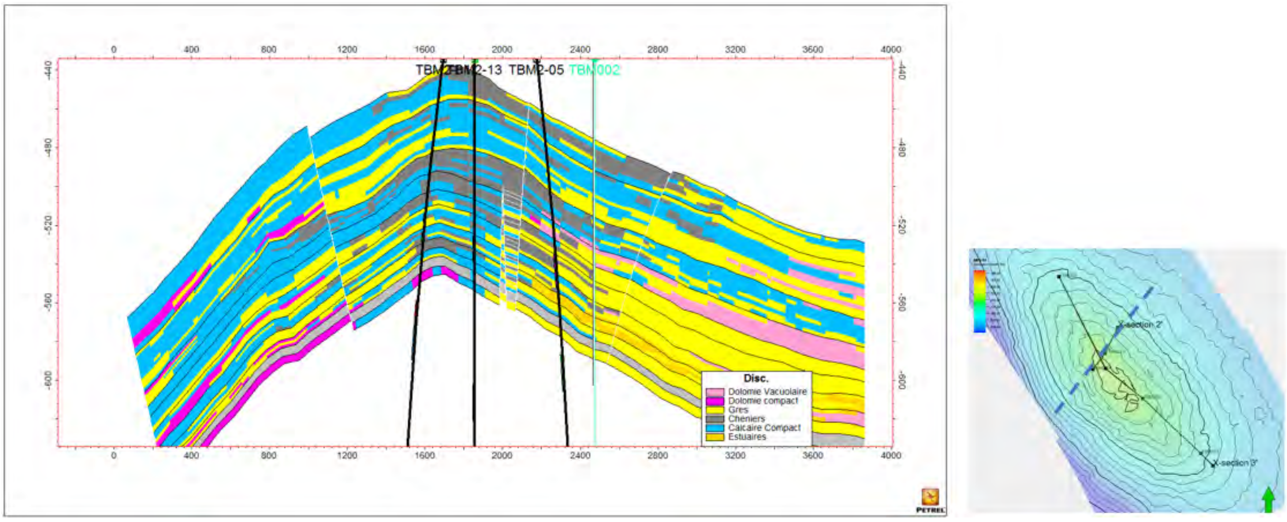


Figure 2.13 Tchibouela Main Turonian. Facies model
From Petrel project; Total 3D static model from 2008

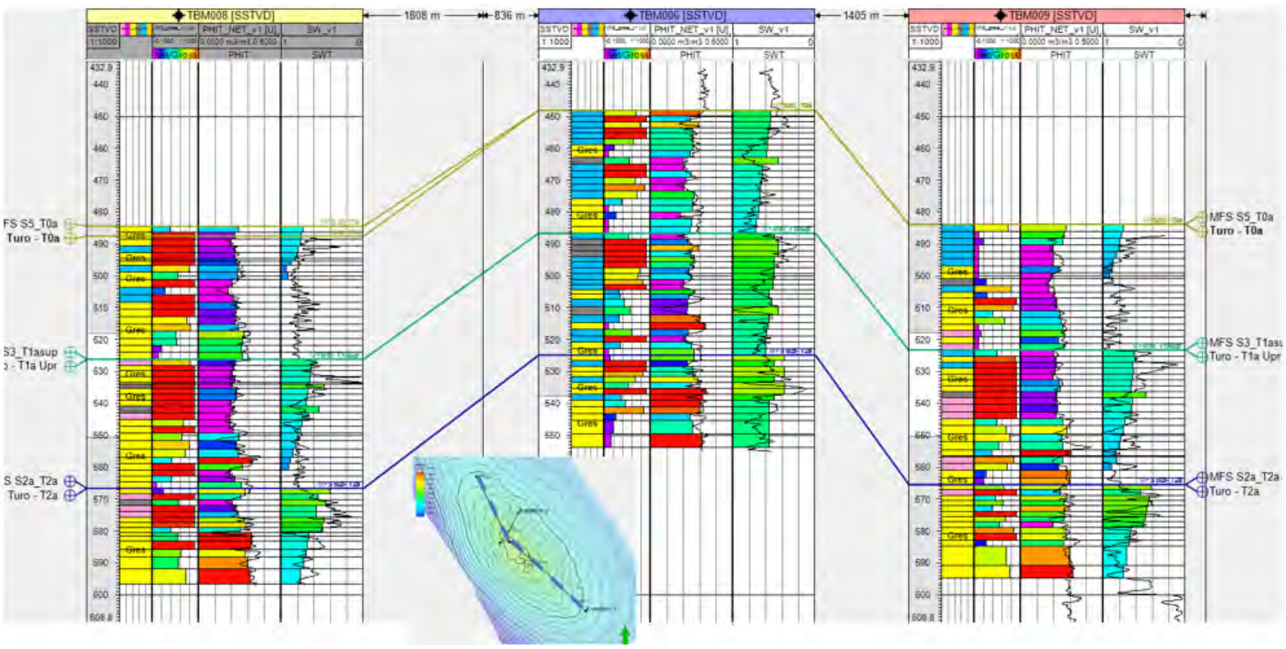


Figure 2.14 Tchibouela Main Turonian. Logs and resetvoir properties
From Petrel project, 3D static model, Total 2008

Figure 2.15 shows a crossection with the Sw model and the reported fluid contacts. The total water saturation, SWT, is used and the log is compared to the Sw-height model for volume calculations. It is also noted that the model does not include any barriers between the different reservoir zones.

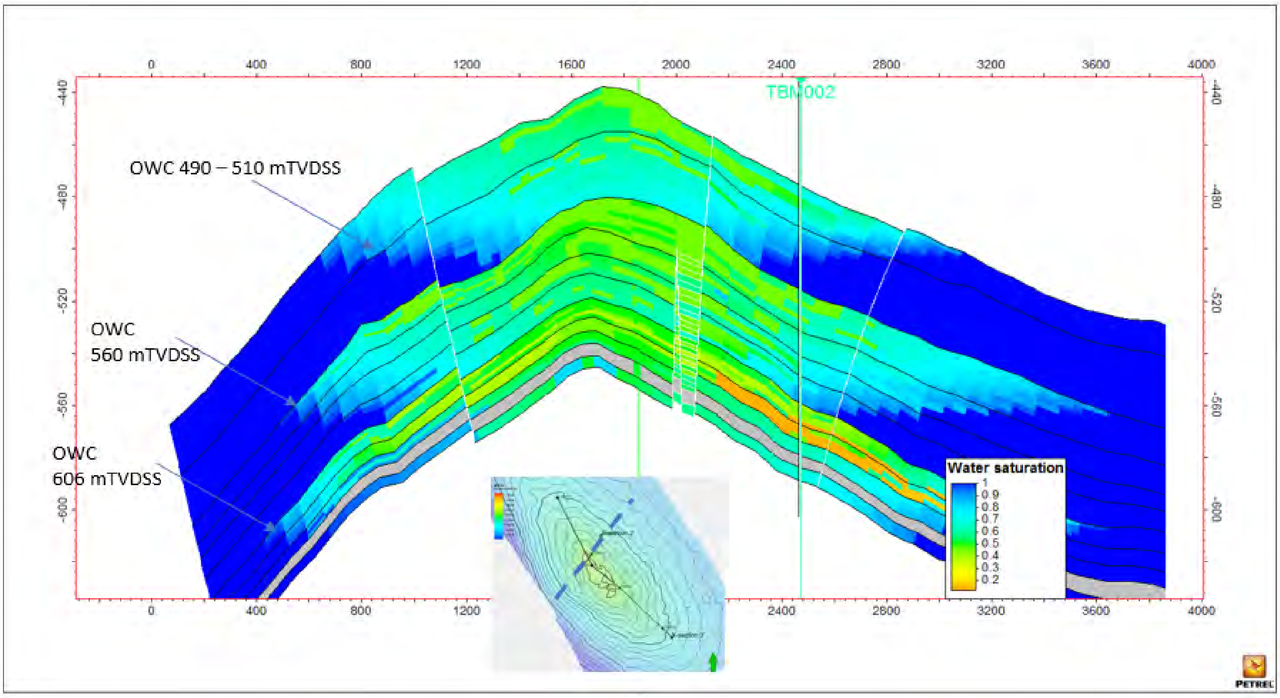


Figure 2.15 Tchibouela Main Turonian. Water saturation model
From Petrel project, 3D static model, Total 2008

The map in Figure 2.16 shows a sum of the hydrocarbon pore volume for all three Turonian zones and illustrates the area on the flank where there is no well control and hence a larger uncertainty in gross rock volume.

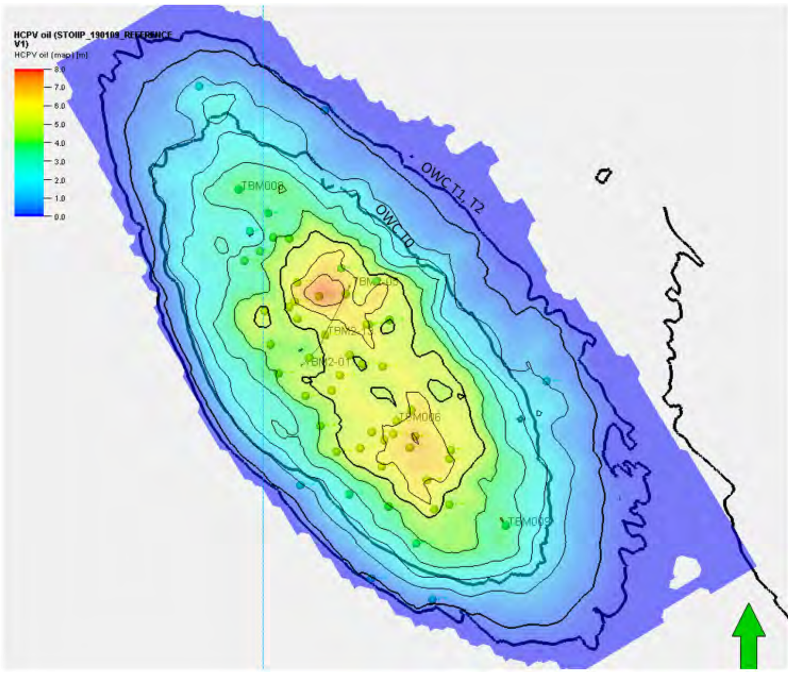


Figure 2.16 Tchibouela Main Turonian. HCPV map
From Petrel project, 3D static model, Total 2008

STOIIP and average reservoir properties in the Turonian base case static model is shown in Table 2.3. These numbers are slightly lower than reported by Perenco in 2018. Note that the average water saturation in the model is high and this is probably an effect of using a Sw-height function that is poorly correlated to reservoir properties. Overall, net/gross and porosity seems to be overestimated while the oil saturation might be underestimated in this model. There is no permeability property in the model.

Table 2.3 Tchibouela Main Turonian STOIIP and reservoir properties in the Total 2008 static model

	Volumetrics					Average reservoir properties in the hydrocarbon zone		
Reservoir	**Gross rock volume (*10⁶ m³)**	**Net volume (*10⁶ m3)**	**Pore volume (*10⁶ m³)**	**HCPV oil (*10⁶ m³)**	**STOIIP (MMbbl)**	**net/gross**	**Porosity**	**Sw**
Turonian T0	201.3	103.4	23.16	7.08	41.0	0.51	0.22	0.69
Turonian T1	291.3	186.2	41.38	14.42	82.6	0.64	0.22	0.65
Turonian T2	440.8	249.7	64.17	16.85	97.8	0.57	0.26	0.74
Total Turonian	**933.4**	**593.3**	**128.72**	**38.35**	**221.4**	**0.58**	**0.24**	**0.70**

STOIIP and average properties for the Tchibouela Main Cenomanian model by Elf (1998) as documented in the report is shown in Table 2.4. AGR had no access to this model.

Table 2.4 Tchibouela Main Cenomanian STOIIP and reservoir properties in the Elf 1998 static model

	Volumetrics					Average reservoir properties in the hydrocarbon zone		
Reservoir	**Gross rock volume (*10⁶ m³)**	**Net volume (*10⁶ m³)**	**Pore volume (*10⁶ m³)**	**HCPV oil (*10⁶ m³)**	**STOIIP (MMbbl)**	**net/gross**	**Porosity**	**Sw**
Cenomanian	626.8	501.4	126.0	93.7	547.5	0.80	0.25	0.26

AGR consider the static model available in the dataroom as being of fair quality.

There is no static model available to AGR covering the Turonian on Tchibouela East in the data room.

A 3D static model from Total dated 2013 for Cenomanian on Tchibouela East was available. The model was basis for dynamic modelling on this reservoir and is also documented in a report. This model is built downwards from Top Cenomanian depth map adding a 50 m thick zone.The facies model includes sandstone and dolomite as the main reservoir facies types, (Figure 2.18). In this field and reservoir level the effective system, PHIE/SWE, has been used, however, the reservoir is quite clean. There is reasonable correlation between net/gross and porosity. Further, porosity in the model compares quite well with the log porosity, (Figure 2.17). The water saturation model is very coarse, the oil saturation is high and compares reasonably well with the logs.

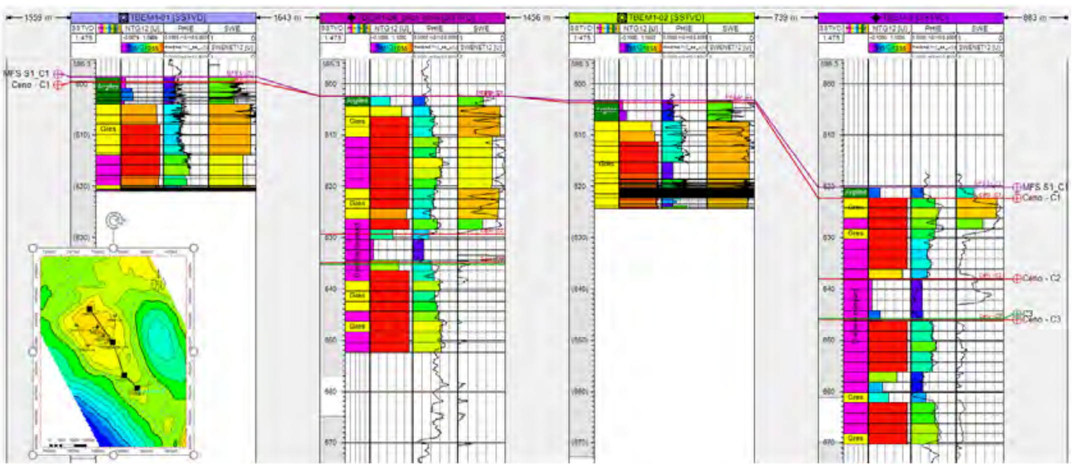


Figure 2.17 Tchibouela East Cenomanian. Logs and reservoir properties
From Petrel project, Total 3D static model from 2013

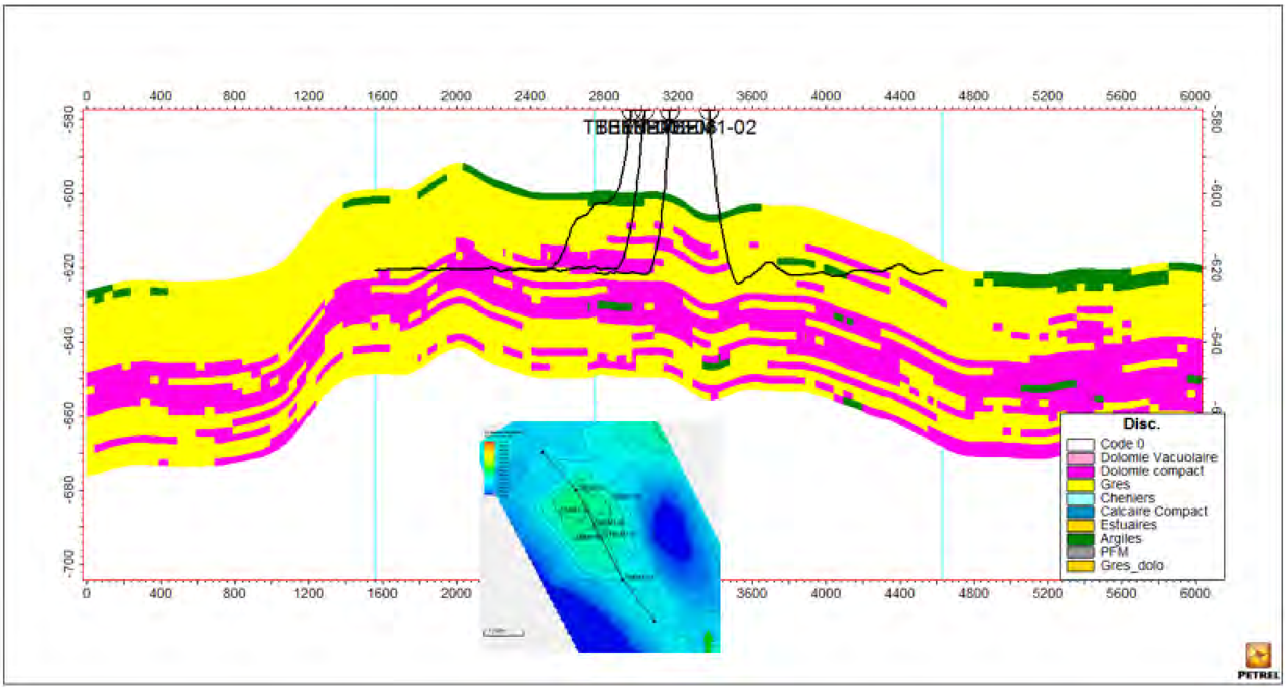


Figure 2.18 Tchibouela East Cenomanian. Facies model
From Petrel project, Total 3D model from 2013

There seems to be an uncertainty related to the OWC. It is reported that the OWC is at 629 mTVDSS and this seems to be in line with the logs, but AGR has observed that there is no closure in the maps on the top Cenomanian level at this depth. A boundary is introduced in the model to limit the HCPV-area. A closure is present at approximately 620 mTVDSS. The STOIIP varies from 48 MMbbl at 620 mTVDSS through 100 MMbbl at 625 mTVD to 148 MMbbl at 629 mTVDSS. As mentioned above under seismic data, AGR could not review the interpretation of the seismic surfaces.

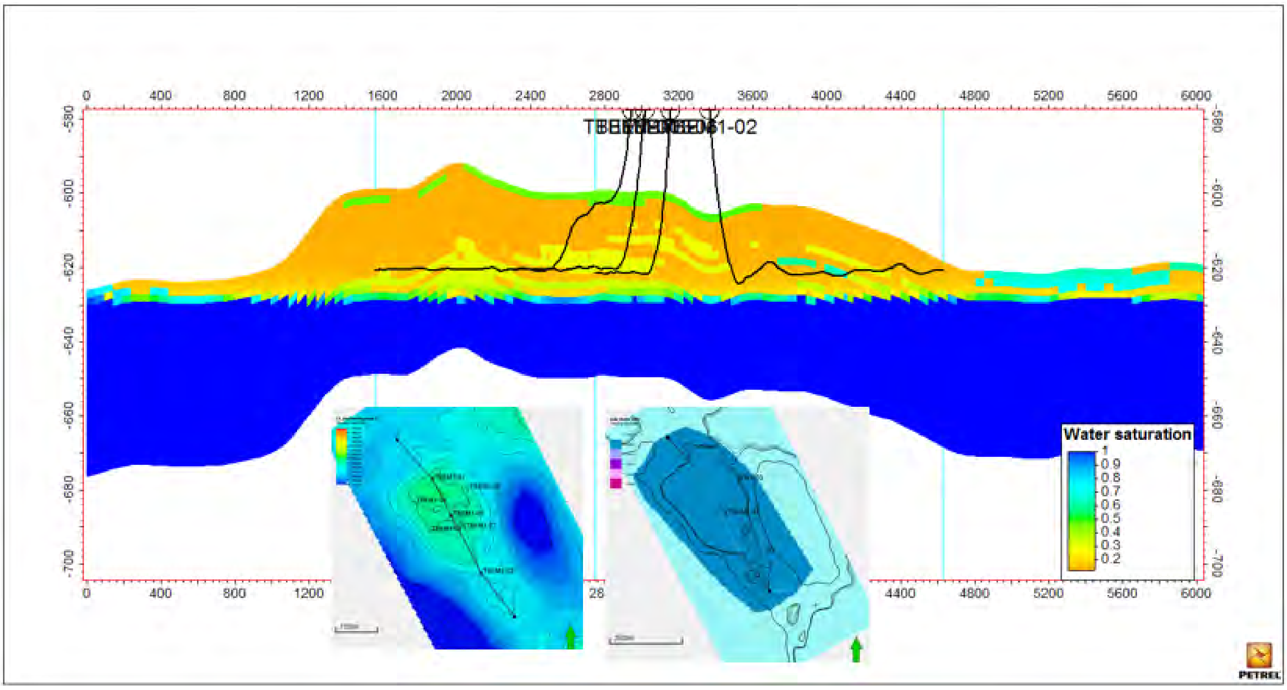


Figure 2.19 Tchibouela East Cenomanian. Water saturation model
From Petrel project, Total 3D static model from 2013. Note the limiting boundary used for volume calculations

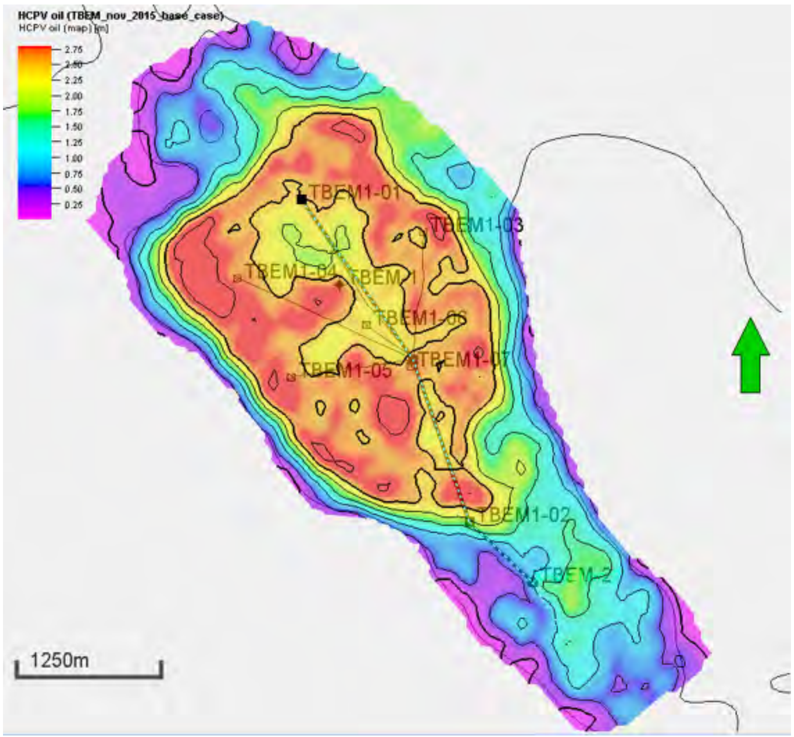


Figure 2.20 Tchibouela East Cenomanian. HCPV map
From Petrel project, Total 3D static model from 2013

AGR consider the property model to be of good quality, but there remains an uncertainty regarding the structural closure and hence to original STOIIP.

Table 2.5 Tchibouela East Cenomanian STOIIP and reservoir properties in Total 2013 static model

	Volumetrics					Average reservoir properties in the hydrocarbon zone			
Reservoir	**Gross rock volume (*10⁶ m³)**	**Net volume (*10⁶ m³)**	**Pore volume (*10⁶ m³)**	**HCPV oil (*10⁶ m³)**	**STOIIP (MMbbl)**	**net/ gross**	**Porosity**	**Sw**	**Permeability - kh (mD)**
Cenomanian	148.9	129.0	30.77	23.98	140.6	0.87	0.24	0.22	1940

2.2.2 STOIIP/GIIP

The base STOIIP estimates for the Tchibouela fields was presented by Perenco in an OCM meeting June 2018.

The operator has currently a work programme for the Tchibouela fields leading to a review of the STOIIP including geological and petrophysical studies. No time plan has been presented for results.

Tchibouela Main
The base for Cenomanian corresponds to the reported volume as calculated from the static model built by Elf in 1998. The base for Turonian is slightly higher than calulated from the 2008 static model and within the uncertainty span reported by Total in the 2016 as 1P, 2P and 3P volumes. AGR has not found the basis for the uncertainty analysis. Overall the upside is reported as larger than the downside for all levels. The uncertainty span in Cenomanian is -5% / + 20% which can be reasonable given the high current recovery from this reservoir. The uncertainty in Turonian is around - 20% / + 45%. AGR can not confirm the high upside based on the material in the data room. Petronor has reported a number for GIIP in their report "201809-28_bes_PNGF Sud - Hemla Review" but AGR has not found the source for this estimate.

Tchiboulea East
There is no static model nor report found in the data room for Turonian on Tchibouela East. There is no information about uncertainty span on Turonian.

AGR can not confirm the base STOIIP for Cenomanian and there seems to exist an uncertainty that should be investigated further. From the reports and 3D static model (Total 2013) a rough estimate indicates a STOIIP range of 48 - 148 MMbbl. However, AGR can not verify this from seismic interpretations.

Table 2.6 Tchibouela Main/East in-place volumes

		STOIIP (MMbbl)			GIIP (MSm3), Free and associated gas		
Field	**Reservoir**	**Low**	**Base**	**High**	**Low**	**Base**	**High**
Tchibouela Main	Senonian	no information			-	1500	-
	Turonian T0	32.8	41.5	49.8	-	-	-
	Turonian T1	78.0	97.5	146.3	-	-	-
	Turonian T2	76.5	95.6	143.4	-	-	-
	Cenomanian	521	548	658	-	-	-
	Total	-	783	-	-	-	-
Tchibouela East	Turonian T0	-	12	-	-	-	-
	Turonian T1	-	22	33	-	-	-
	Turonian T2	-	9	-	-	-	-
	Cenomanian	-	76	-	-	-	-
	Total	-	119	-	-	-	-

2.2.3 Reservoir Engineering

Reservoir
AGR has evaluated the resource numbers and profiles in relation to the definition of the various resource classes. The main sources of data are the presentation material given by Petronor, the former operator Total and OCM/TCM material and production forecast by Perenco. Historical production data (up to April 2018) and a static Petrel model from 2009 is also available (only Turonian). No Eclipse model (dynamic model) has been made available to AGR for Tchibouela.

The field constitute of three disconnected reservoirs: Senonian, Turonian and Cenomanian, see Figure 2.7. Tchibouela came on stream in 1987 and had a peak production of approx. 70 000 stb/d in 1995, see Figure 2.21. Since then the oil production has been on decline. Current production (first quarter 2018) is 12 500 bopd, with 93 % water cut. 53 % of the total oil production is coming from Cenomanian. All the wells from wellhead platforms TAFP and TAF1 has ESP as artificial lift, with the exception of TBM1-06, which produces half of the oil in Turonian 2. All wells from platform TAF2 have gas lift.

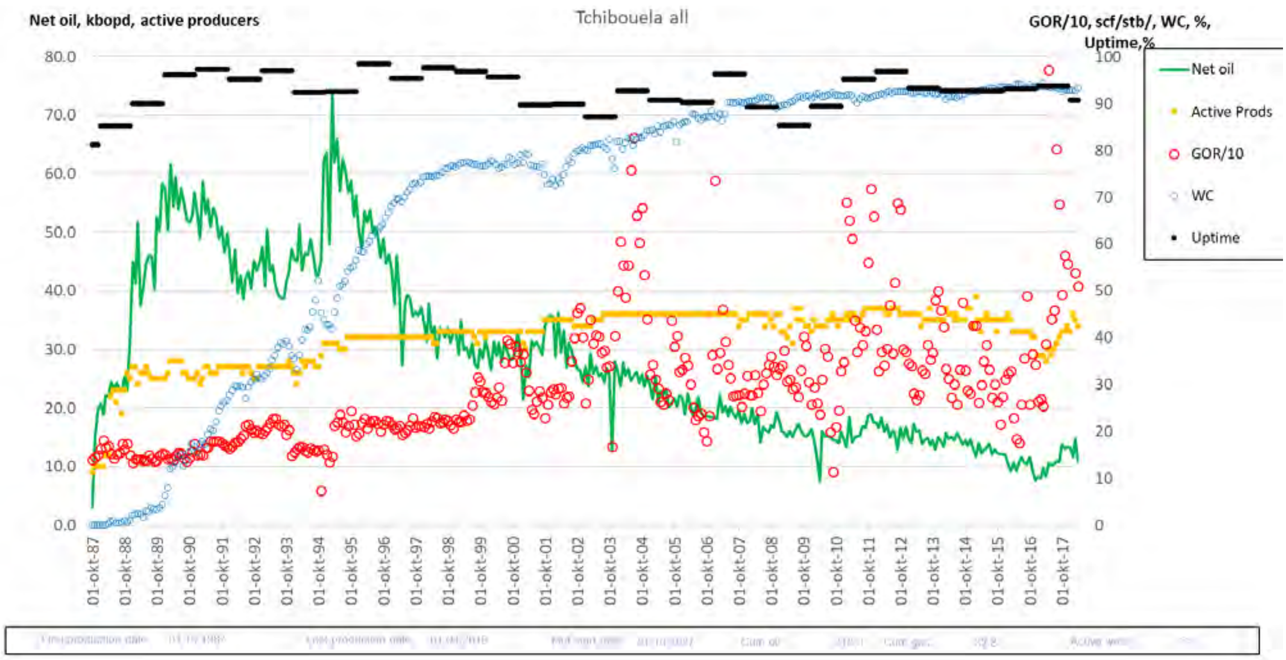


Figure 2.21 Tchibouela Main. Historic oil production rate
Oil rate, water cut, GOR, uptime and no. of active wells from October 1987 to April 2018, combined from Turonian and Cenomanian.

<u>Senonian</u>
The reservoir has a major gas cap with a thin oil leg. Gas from the two gas producers in Senonian is used for gas lift and electricity production. This formation has never had any oil production.

<u>Turonian</u>
The reservoir is divided into three distinct formations; T0, T1 and T2, with thicknesses of 40 m, 30 m and 20 m, respectively. The pressure is maintained by natural water influx in all three formations. In addition, there is an active water injector in Turonian 2 (T2), injecting 2 500 bwpd. There is also a water injector in T1, which currently is shut in. The Turonian reservoirs have 13 active, vertical oil producers with an oil production of 6 000 bopd and a water cut of 85 %. The solution GOR is low, ranging from 20 - 30 Sm^3/Sm^3, and an oil viscosity of 5 - 15 cP. Reservoir pressure estimated in 2013 was approx. 40 % lower than initial pressure. The permeability varies between 1 and 2 000 mD. Accumulated oil production from Turonian at current date is 59 MMbbl with a recovery factor of 25 %.

<u>Cenomanien</u>
The reservoir has 20 active vertical oil producers with a very active aquifer. There is thus no injection into this reservoir. Reservoir pressure estimated in 2013 shows a depletion of approx. 10 % vs. initial pressure. The permeability is estimated to higher than 2 000 mD, with an oil viscosity of 9 cP. The solution GOR is

approx. 28 (157 scf/stb) Sm^3/Sm^3. Accumulated oil production from Cenomanian at current date is 259 MMbbl with a recovery factor of 47 %. Current oil production is 6 700 bopd with a water cut of 95 %.

Status
So far in 2018 three wells have been re-perforated in Turonian and acid stimulated by bull-heading, given an oil increment of 1 150 bopd (well TCDM1-23, -10 and -16). Planned workovers for the rest of 2018 concerns ESP replacement, re-perforation and selective stimulation (TCDM1-19, -11, -14 and -33ST). No estimation of incremental oil for these workovers is given. However, production forecasting significantly above budget is given in the 2018 TCM and OCM in June 2018.

Tchibouela East

The platform on the field closed mid 2016 due to blocking of an export pipe (6 km of 6 inch diameter). At cessation in 2016 all six wells in Cenomanian were closed. Four of these were closed due to ESP breakdown, 2 due to water cut exceeding 99 %. Previously, they produced with a very high water cut (above 98 %) at natural depletion. Oil viscosity is 11 cP with permeability ranging from 500 - 1 000 mD.

Since first oil only one well has been active in Turonian producing with natural depletion. The well produced approx. 170 bopd at closure, with water cut below 20 %. Total production in Turonian reached 1.3 MMbbl with a recovery of 3 %. Oil viscosity is 16 cP with permeability ranging from 50 - 250 mD.

AGR has no information regarding any possible re-opening of the field. This report, therefore, does not contain any resources from Tchibouela East. However, the low recovery factor should indicate significant upside, especially in Turonian, if the operator considers any re-development of the field.

Production Forecasting
AGR has estimated the future oil production rates from the existing wells to generate production profiles used as the basis for reserves estimation.

The contribution from the existing wells is derived from different types of decline curve analysis (DCA):

1. Oil rate versus time for the entire reservoir
2. Oil rate versus time for each of the two separate reservoirs Cenomanian and Turonian, then summed together
3. Water cut versus accumulated oil
4. Oil rate versus accumulated oil

The first method is used as the main basis for the reserves estimation. The three others are used as complementary information and to get a better view about the spread in reserves. Figure 2.22 and Figure 2.23 displays the results of method 1) and 3). The hyperbolic base case prediction curve for method 1) uses a decline exponent of 0.7. This exponent indicates pressure support, as also confirmed in the presentation "Complément réservoir TBM TBEM" from 2014, stating that especially Cenomanien has an infinite and strong aquifer. The high and low cases has b exponent of 1 (harmonic) and 0 (exponential), respectively, and a slightly different initial decline rate than the base case. A similar exercise for the base case was also done on the split oil production rates from the two independent reservoirs Cenomanian and Turonian, summing the results afterwards to get the entire field. The latter yielding 17 % less volumes than the DCA done on the combined profile.

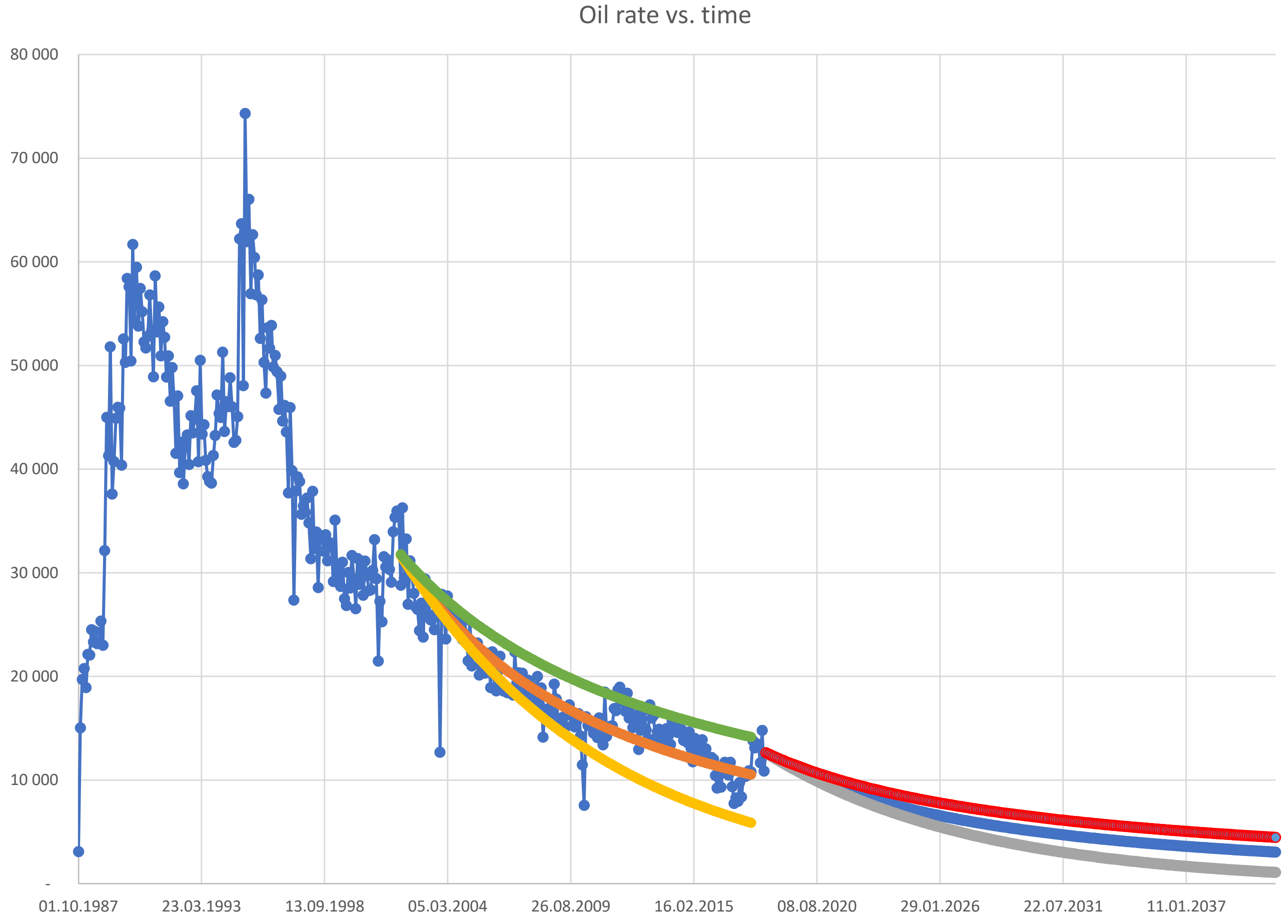


Figure 2.22 Tchibouela Main (Cenomanian+Turonian). Historical production and DCA prediction
The base case hyperbolic decline for prediction is based on b exponent of 0.7 (blue line). The orange match line has the same initial decline and b exponent as the base case prediction, and is thus displaced parallel to the base case prediction line. This line is only displayed to show the reader how the prediction would look like placed in the history. Likewise for the high (red in prediction) and low (gray in prediction) cases.

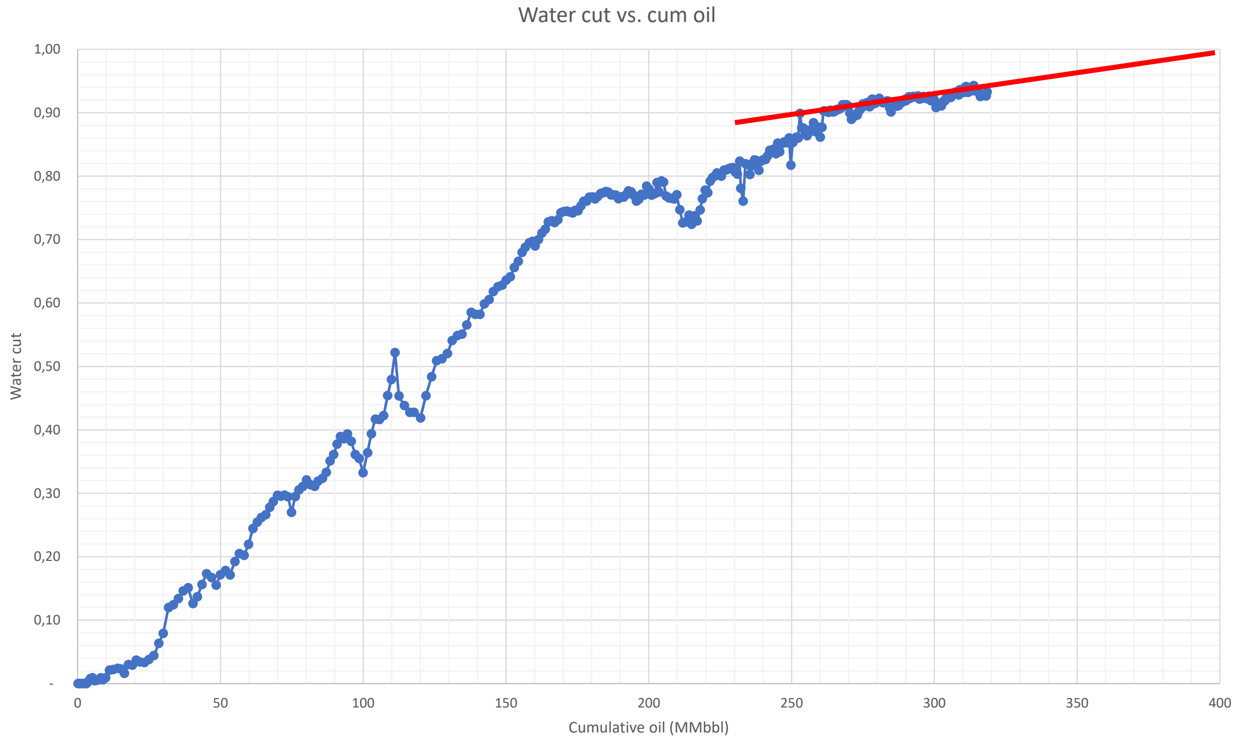


Figure 2.23 Tchibouela Main. Water cut vs. accumulated oil
Extrapolation of the water cut up to a certain level will give an indication of the total oil production

Method 3) extrapolates the water cut to 98 % yielding the cumulative oil production. Similarly, method 4) extrapolates the oil rate to 2041 with the corresponding future oil volume. Table 2.7 displays the results for the different DCA methods at the end of year 2041.

Table 2.7 Technical volumes with different DCA methodes

	Oil rate vs. time, entire reservoir	Oil rate vs. time split between Cenomanien and Turonian	Oil rate vs. cumulative oil	Water cut vs. cumulative oil
Oil volume end 2041 (MMbbl)	52	41	55	63

AGR has chosen to use method 1) as the basis for the reserves profile. The technical volume of 52 MMbbl in 2041 is approximately an average of the spread in volume for the different methods. Harmonic (b exponent=1.0) and exponential (b exponent=0.0) decline have been used to define the high and low cases. But the initial decline rate is adjusted to also reflect the results from the other methods. The high and low case has a range of +/- 20 % versus the base case.

Recovery Factors
The overall recovery factors for oil from existing wells are given in Table 2.8.

Table 2.8 Tchibouela Main recovery factors

	Oil RF by 31.12.2017 (%)	Oil RF by 31.12.2041 (%)
Tchibouela Turonian	30	-
Tchibouela Cenomanian	47	-
Tchibouela all (sum Tur. + Ceno.)	40	49

Reserves and Contingent Resources Classification
The production profiles used as the basis for reserves for Tchibouela are shown in Appendix A2 - Production Profiles. The underlying reserves are classified according to SPE-PRMS as follows:

- "On production": Production from existing wells

The reserves category also includes the future regularly maintenance and workovers on the field that is part of the long term plan and is considered as the daily management. This is indirectly incorporated in the decline curve analysis when estimating future production, as this also has been done on a regular basis in the past.

Back in 2016 the operator Total made plans of increasing the oil volumes by 26 MMbbl, split into two phases. The work comprised drilling of new wells and sidetracks in addition to well workovers. Since then the operatorship has been changed. Petronor, licence partner, has proposed new plans for increasing the producible volumes. A preliminary plan is as follows:

- 2 workovers in 2019
- 4 infill wells + 4 water injectors in 2020 - 2021, targeting particularly Turonian
- 4 infill wells in 2022 - 2023

The suggested plan looks feasible. However, these projects needs more studies and detailing before they can be sanctioned, and as such they are currently classified as contingent resources; "Development Unclarified". Before being booked as reserves a development plan, positive economy, a commitment from the licence and relevant approvals from the authorities, are required.

AGR considers the 2 workovers planned for 2019 as part of the daily maintenance/management of the field, since workovers have been done continuously in the pase. These volumes are thus already indirectly incorporated in the reserves by the DCA, and is not added to the contingent resources found in Table 2.11.

2.2.4 Recoverable Volumes

Reserves
The production profiles have been checked for economic cut-off using following assumptions, with PV Reference Date: 1.1.2018.

Table 2.9 Economic Assumptions

Economic Assumptions		
Oil Price	USD/bbl	70.0
Gas Price	USD/mscf	6

The reserves are given in the table below. The cut-off year is defined as the last year with positive cash-flow based on cost profile see A3 - Cost Profiles. For all cases, the economic cut-off year is reached at the end of 2041.

Table 2.10 Tchibouela gross reserves as of 1.1.2018

Reserves, AGR review	**1P**	**2P**	**3P**
Oil, MMbbl	41.13	52.49	62.83
Gas, BScf	16.78	21.42	25.63
NGL, MMboe	-	-	-
Total, MMboe	**44.11**	**56.30**	**67.39**

Contingent Resources
The contingent resources are given in the table below.

An explanation of contingent resources related to well workovers and infill drilling is given in chapter 2.2.3 Reservoir Engineering.

Table 2.11 displays the contingent resources for Tchibouela Main. The 2C resources include two new producers commencing production during 2020 and two during 2021. At the same time two water injectors will be drilled in mid 2020 and mid 2021, respectively. We have no information about any estimated initial start rate for a future infill well for Tchibouela. Nor have we any information if the wells will be horizontal or vertical. As the injectors can support multiple wells, and if we assume the wells to be slanted, AGR have estimated the initial rate of each new producer to 1000 bopd/well. This estimation is uncertain, but probable. The estimated start rate is above the average of nearly 400 bopd from a current producer in 2018 (only vertical). The 2C resources' wells are set with the same decline rate as the 2P profile (same b exponent, but higher initial decline). The 3C resources adds additionally two new infill wells in mid 2022 and two new in mid 2023. As no water injectors are drilled in conjunction with these wells and the fact that they are starting later in time (reservoir more water flooded), these wells are assumed with a start rate of 700 bopd/well. These four wells are set with the same deline rate as the 3P profile (same b exponent). For the 1C resources we have assumed that the start rate is slightly less than that of the 2C resources (700 bopd/w) for the four planned producers in 2020 and 2021 (includes also the four WI), and that they follow the 1P decline. The gas resources are estimate by multiplying the oil volume by the average GOR for the two last years.

Table 2.11 Contingent Resources Tchibouela Main (100 %) verified by AGR as of 1.1.2018 to 31.12.2041

	Oil, MMbbl			**Gas, BScf**			**Total, MMboe**		
Gross	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Tchibouela Main	6.2	12.0	20.7	2.5	4.9	8.4	6.6	12.9	22.2

2.2.5 Facilities Development

The Tchibouela field facilities have been developed as seen in Figure 2.24 and consists of three bridge linked jacket platforms which includes crude oil processing-, flaring- and drilling/well-head functions and two single jacket well-head platforms. Production started in 1987. Oil is exported to Denjo onshore terminal.

The field platforms should have significant spare capacities with the current operations and coming production trends, as seen from the historical production curves.

AGR observations

- AGR has not seen any Design Basis document (including design capacities and - lifetime for structures / critical equipment) and would flag lifetime as a potential concern, especially with respect to corrosion issues.
- AGR has been told that the Operator have two workover units owned by themselves and subsequently AGR do support the relative active workover strategy.
- AGR has not seen any well slot overview and status and would flag that this could be a future challenge.
- AGR does expect that Perenco in some way has withheld Total's ordinary operation-/maintenance activities and/or any own similar programs, as AGR has not seen these. NB! The following wording copied from the visual inspection in October 2016 is alarming "The status of the plant and the equipment indicates, that there is No applied preventive maintenance. The applied maintenance philosophy is based on the Break Down Maintenance (Run to Failure- Repair only when it fails)."
- AGR does find the 2018 CAPEX (cathodic protection, power generation update and sealine recovery) and the 2018 OPEX (mainly well workovers / new ESPs) to be realistic.
- AGR does support the cost figures being used in the economical analyses, benchmarking these with relevant in-house cost data.
- AGR has not seen any Risk (uncertainty) Management analyses and subsequent unified "top ten" Risks Matrix from OC-and TC meetings.

AGR conclusions

- AGR concludes that there is no technical show stoppers with respect to further production in the near future, however, AGR would alarm that design lifetime (and subsequent technical integrity status) for critical steel structures and - key equipment could be an area of concern in time (especially corrosion issues).
- AGR does support Petronor's aim to follow the operators activities closely and ensure that all measures are taken, which will increase the producibility of each field.
- AGR would recommend Risk Management as an value add system, especially in implementing Petronor's upside potentials and also highlighting critical downsides as Petronor see it.

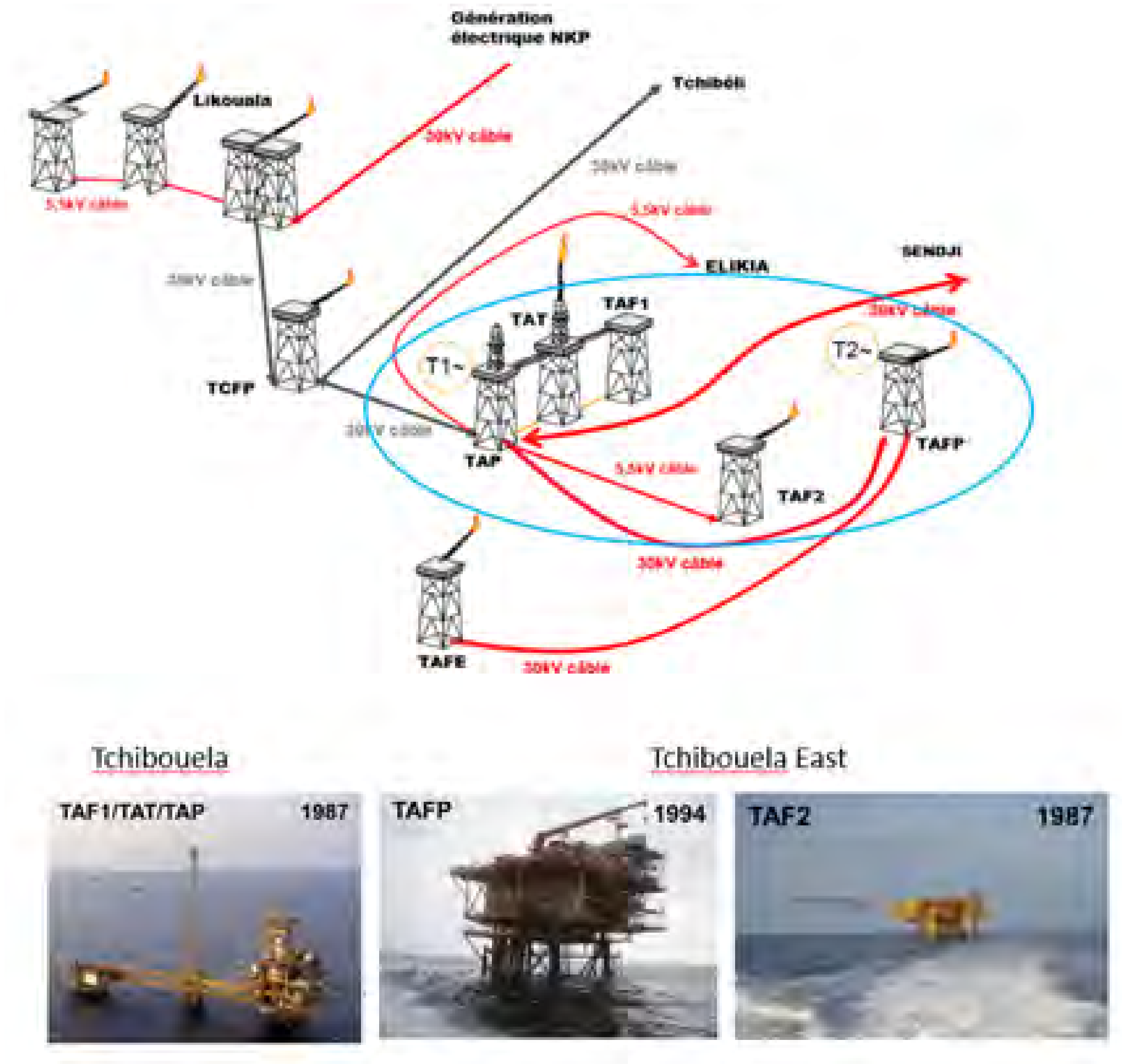


Figure 2.24 Tchibouela. Field facilities layout

2.3 Tchendo

2.3.1 G&G

Geological setting
The setting for Tchendo is similar to Tchibouela, with the reservoir levels in the Turonian and the Cenomanian. The field is located south of Tchibouela and the deposional environment is similar but further basinwards. Additional production is ongoing in the younger low permeability Emeraude Silt of Senonian age.

A depth map of the Turonian reservoir and generalized profiles of the field is shown in Figure 2.25. The structure is a four-way closure divided by a southwest-northeast normal fault which is dipping towards the southeast. The field is appraised by four exploration wells and together with the development wells the structure is well defined.

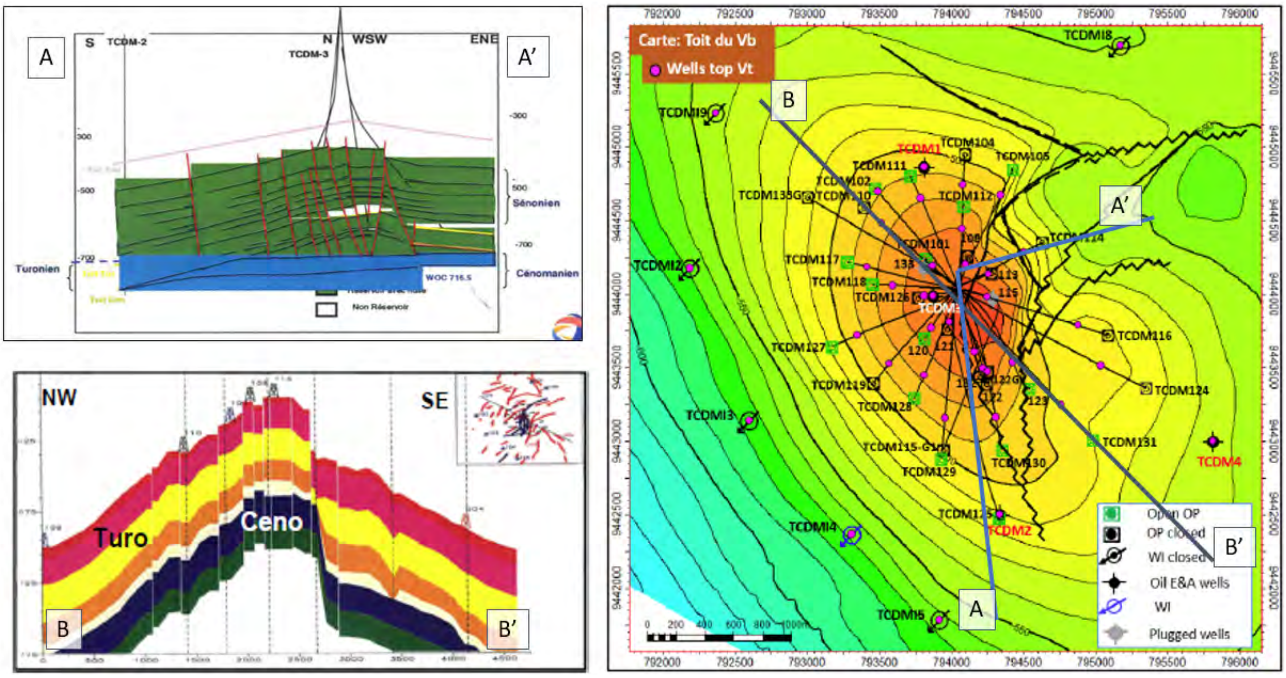


Figure 2.25 Tchendo. Top Turonian reservoir depth map and schematic crossection of reservoir levels

Reservoir Properties
Reservoir properties in Tchendo are summarized in Table 2.12 as reported in the data room documentation for the Senonian, Turonian and Cenomanian.

AGR has reviewed the log data provided for the Senonian, Turonian and Cenomanian. Accordingly, full set conventional well logs are acquired for the entire drilled section. In general quality of the well logs and petrophysical results is good however, petrophysical interpretation is only performed over the Senonian interval. Reservoir summary over the Senonian for the Tchendo wells are tabulated in Table 2.13.

Table 2.12 Reservoir parameters for the Tchendo field

Reservoir	Thickness (m)	net/gross	Porosity	Sw	Permeability (mD)
Senonian	~200m	-	0.23	-	1 - 50
Turonian	~40	-	0.24	-	10 - 1000
Cenomanian		-	0.26	-	> 2500

Table 2.13 Reservoir parameters for the Senonian Tchendo field. From AGR petrohysical evaluation review

Well	Zone	Thickness (m)	net/gross	Porosity	Av Sw (in HC-zone)
TCDM_1	Senonian	214	0.99	0.226	0.40

Well	Zone	Thickness (m)	net/gross	Porosity	Av Sw (in HC-zone)
TCDM_2	Senonian	224	0.99	0.231	0.47
TCDM_3	Senonian	213	0.99	0.256	0.40
TCDM_4	Senonian	215	0.88	0.218	0.53
TCDM_1-01	Senonian	276	0.91	0.227	0.21

Seismic Data
There are two surveys, a PSTM from 2001 and a PSTM from 1988 reprocessed in 2006 (Figure 2.26).

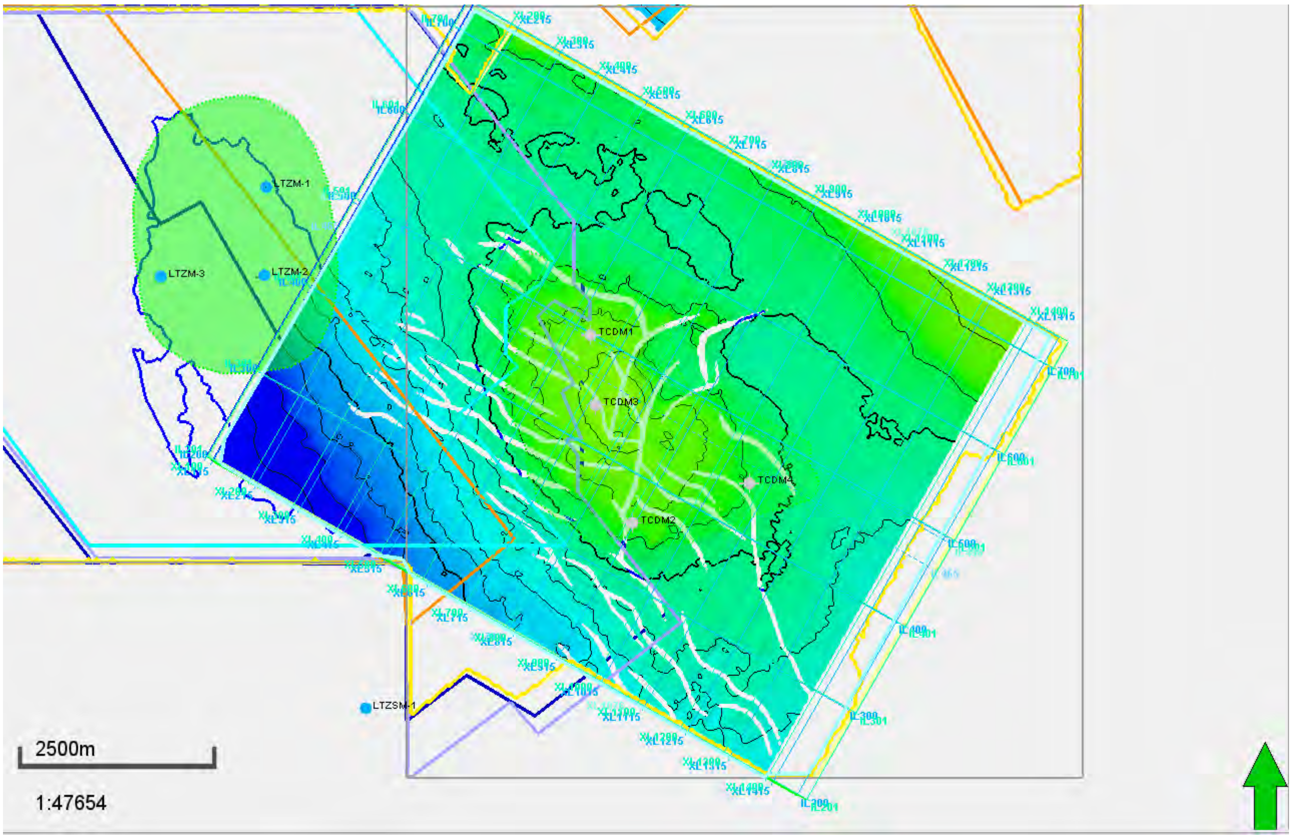


Figure 2.26 Tchendo. Seismic coverage with Top Senonian time structure map.

The PSTM 2001 quality ranges from poor to fair. There is a fair amount of shallow gas chimneys that disrupt the data particularly on the western side of the structure. Due to the large amount of gas the frequency content is quite low. The crest of the structure is within a gas cloud shadow. The reprocessed 2006 data shows better continuity though with lower amplitude over the areas affected by shallow gas effects. With the improved processing the data quality is between fair and good.

No seismic well tie has been found within the documentation or the Petrel projects provided.

The seismic interpretation as compared to the seismic data quality is fair. It gives the overall structural picture but it is quite inaccurate.

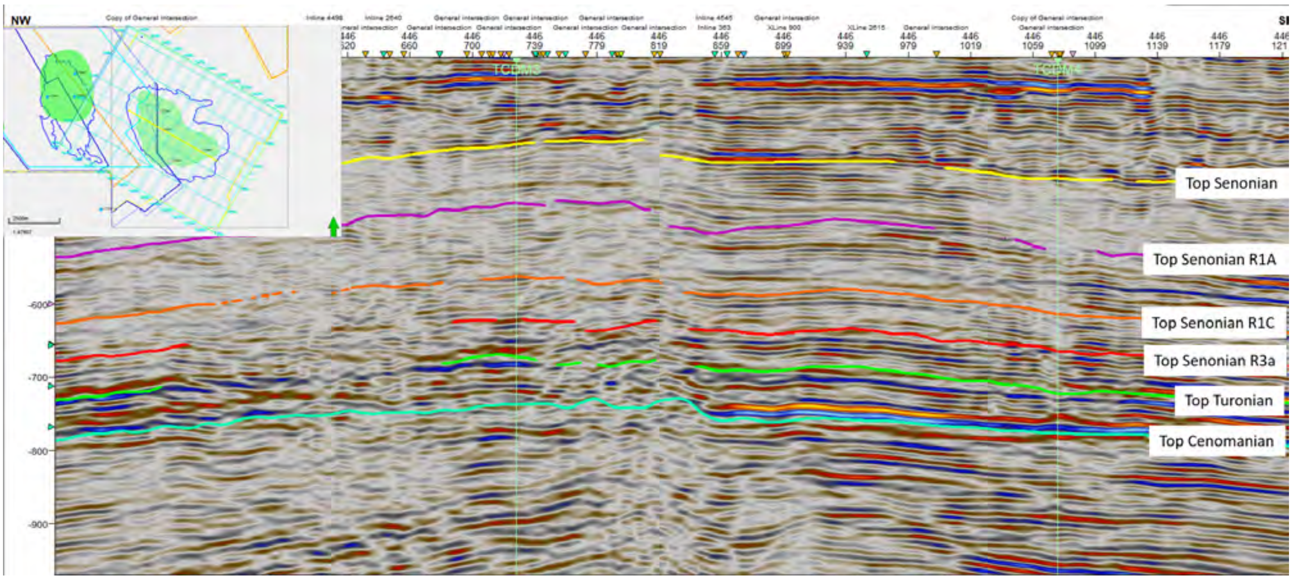


Figure 2.27 Tchendo. Inline Seismic 446 with interpretation

Static Models
Overall, there are no or very poor geological 3D models for this field available to AGR.

AGR has access to one static model for Tchendo in Petrel. The 3D static model from 2015 is covering the Senonian only. However, the geometry in this model is heavily distorted. It is probable that the process of correction to abundant well tops has ruined the original structural depth maps. However, properties and logs in some of the wells in the model can be seen in Figure 2.28. The figure indicates that porosity is highly overestimated while oil saturation is slightly underestimated in the model compared to the logs. Due to distorted geometry and poor property model no reliable volume calculations can be done in this model.

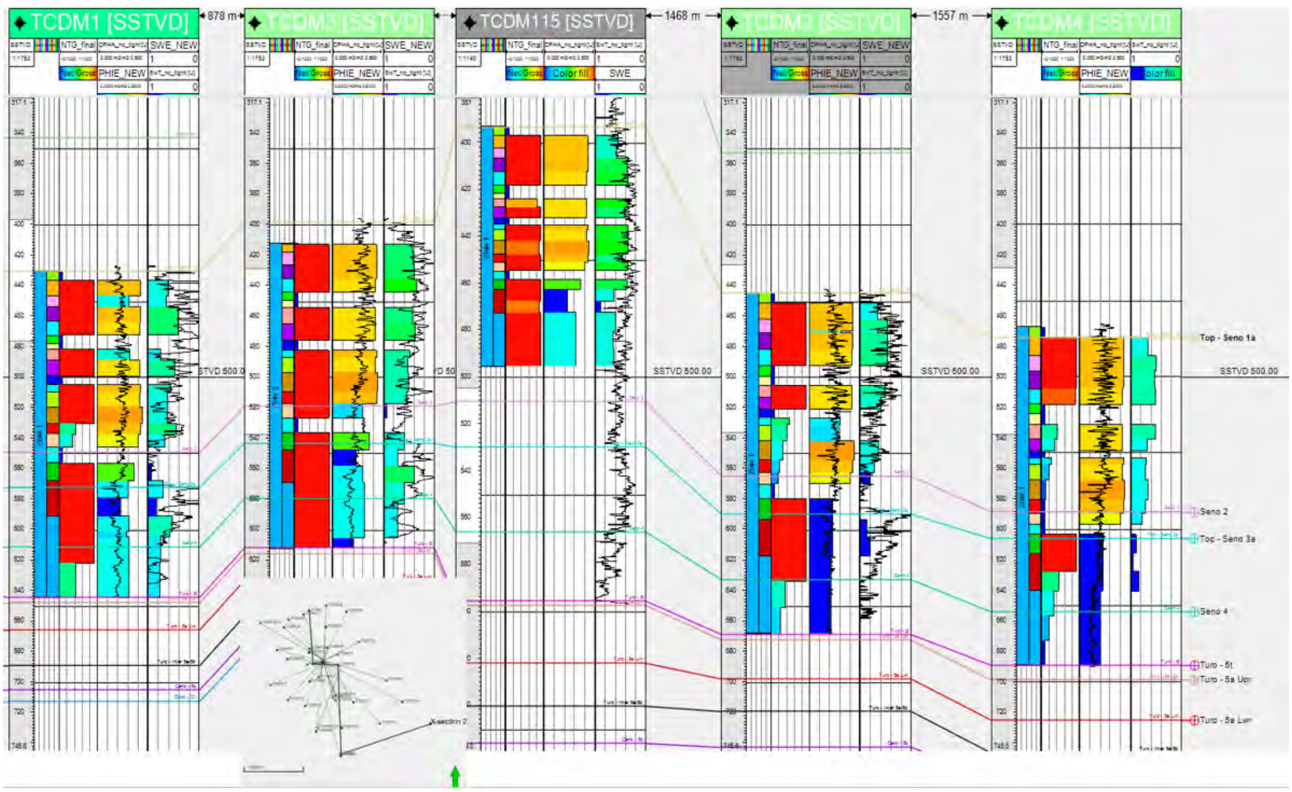


Figure 2.28 Tchendo Senonian. Logs and reservoir properties
From Petrel project; 3D static model Total 2011/2012

There is a handout from a licence meeting in 2004 where Total describes a geological model for the Senonian but this is not the same as the model in the dataroom. In this handout a considerable uncertainty related to fluid contacts is shown; structural closures and observed oil-down-to situations do not match for the different internal reservoir zones in Senonian.

There are no Petrel static models available for Tchendo Turonian nor Cenomanian in the data room.

The latest geological model for Tchendo Turonian is described in an Elf report from 1996, but this seems to be outdated. According to Perenco a static model for Cenomanian was built by Total in 2014, but AGR has not found any documentation of this work.

AGR has observed that Total has built a static model over Albian in 2014 for Tchendo. No further information of this model was available.

Perenco is in the process of rebuilding the geological models for this field. Seismic interpretation for Senonian is reported to be finished and ongoing for the deeper levels. Petrophysical evaluation of the wells will soon be finished.

2.3.2 STOIIP/GIIP

The STOIIP for Tchendo field is listed in Table 2.14.

In the OCM meeting from June 2018 a STOIIP of 1100 MMbbl was reported by Perenco as a base estimate for the Senonian. This number can be traced to the licence meeting in 2004 from Total where different filling scenarios were defined as Min/Med/Max cases. The estimate includes two reservoir units in Upper Turonian and gives a range of 820/1100/1430 MMbbl. However, Total reports an uncertainty span as 1P, 2P and 3P volumes in 2016 as shown in Table 2.14.

The base STOIIP estimates for the Turonian and Cenomanian was presented by Perenco in the OCM meeting from June 2018. The uncertainty span is as reported by Total in 2016 as 1P, 2P and 3P volumes. No uncertainty span is reported for Cenomanian.

AGR can not confirm the STOIIP estimates for the Tchendo field for neither of the reservoir levels based on the infomration provided. It should be noted that Perenco are currently building new static models, but no information about this was available to AGR.

There are no gas caps and all GIIP is therefore associated gas but there is no information about GIIP estimates.

Table 2.14 Tchendo in-place volumes

		STOIIP (MMbbl)		
Field	**Reservoir**	**Low**	**Base**	**High**
Tchendo	Senonian	628	842	1095
	Turonian	139	155	178
	Cenomanian	-	31	-
	Total	-	1028	-

2.3.3 Reservoir Engineering

Reservoir

AGR has evaluated the resource numbers and profiles in relation to the definition of the various resource classes. The main sources of data are the presentations given by Petronor and the former operator Total, as well as historical production data up to April 2018. There also exist older, separate Eclipse models of each of the three formations: Senonian (2006), Turonian (2011) and Cenomanian (2005), in addition to a static Petrel model from 2011. Since the Eclipse models have not been history matched recently (newest model from 2011), AGR has chosen not to use the models for reserves estimation.

Tchendo was discovered in 1979 and came on stream December 1991. Peak production of 23 000 bopd was reached in 1993, and has since then been on decline. The field consists of three separate reservoirs; Senonian, Turonian and Cenomanian. The water depth is 95 meter, with a reservoir depth of 450-750 meter. In total, 29 producers and 8 injectors have been drilled on the field, of which 16 wells were on production April 2018. Current oil rate is 4 600 bopd (290 bopd/well) with a water cut of approx. 60 %, see Figure 2.29.

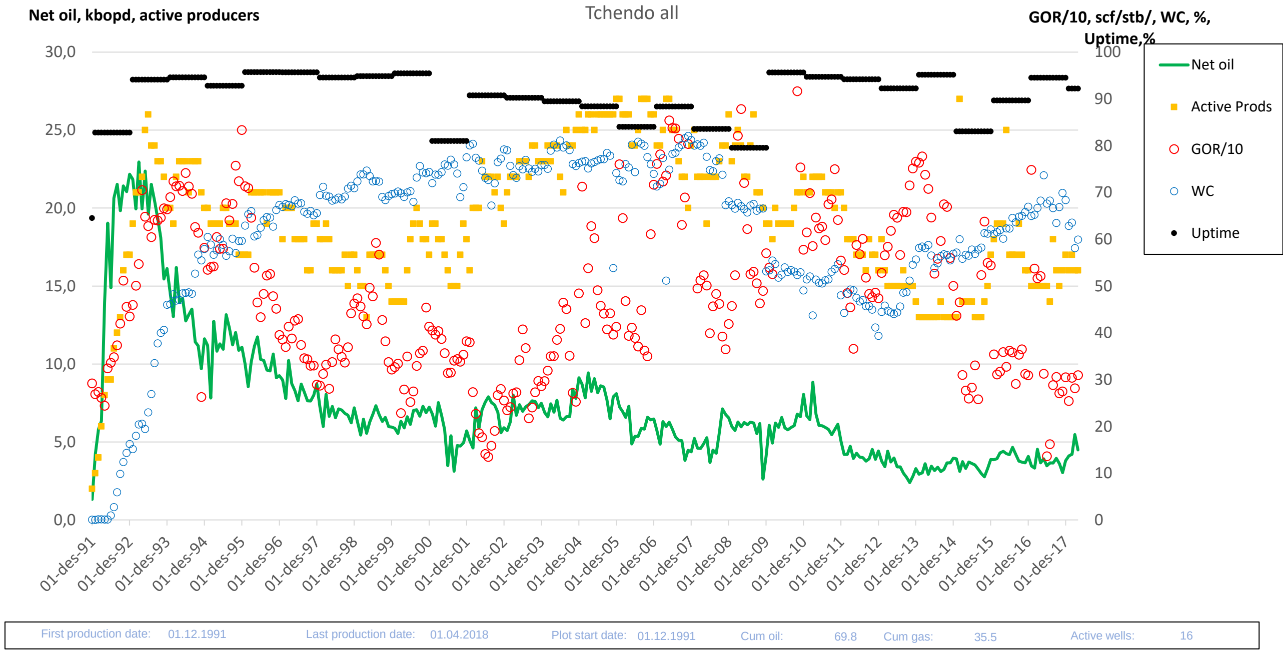


Figure 2.29 Historic oil production rate from entire Tchendo
Oil rate, water cut, GOR, uptime and no. active wells for both Senonian and Turonian reservoirs.

<u>Senonian</u>

Today 7 wells are producing 1 900 bopd from this reservoir, with a water cut of 18 %. Historical production is only 11.2 MMbbl of oil, yielding a recovery factor of only 1 %. The oil viscosity is from 3 - 4 cP, with a permeability below 50 mD.

<u>Turonian</u>

9 wells are currently producing 2 700 bopd (300 bopd/well) with a water cut of approx. 70 %. Originally 8 wells were injecting water into the Turonian reservoir. In 2017, only 2 water injectors were injecting 3 400 bwpd. There has been WI integrity problems due to leakage on the water flowline. According to the PRIME 2016 (Total) there is thus too little water injection into Turonian. Historical production is 41 MMbbl of oil, yielding a recovery factor of 26 %.

<u>Cenomanian</u>

There has been no production from the Cenomanian reservoir since 2009. A total of 17.4 MMbbl of oil has been produced from the Cenomanian reservoir, reaching a very good recovery of 56 %. The oil viscosity is around 5 cP with rock permeability above 2 500 mD. AGR is not aware of any plans for future production from this part of the reservoir.

Status

From 2017 - 2018 several workovers have been performed, resulting in a 20 % increased oil production from Q1 2017 to Q1 2018. Wells have been re-perforated and selective stimulated, and later in 2018 two wells will have the ESPs replaced, one will be attemted re-started (no reason for the shut-in is mentioned) and one will have a proppant clean-out.

Production Forecasting
AGR has used the historical production rates from the existing wells as the main source for prediction since only older vintage dynamic model has been available for evaluation.

Like on Tchibouela, the contribution from the existing wells is derived from different types of decline curve analysis (DCA):

1. Oil rate versus time for the entire reservoir
2. Oil rate versus time for each of the two separate reservoirs Cenomanian and Turonian, then summed together
3. Water cut versus accumulated oil
4. Oil rate versus accumulated oil

The contribution from the existing wells as shown in Figure 2.30 is derived from decline curve analysis (method 1) with a decline exponents of 0.5 for the base case. This decline exponent indicates pressure support. The predicted base cumulative oil production from 1.1.2018 to 31.12.2041 from the existing wells, is 21 MMbbl, see Table 2.15. AGR have chosen to use this techinque as the main predictive tool, with the others as supportive methods for estimating the range.

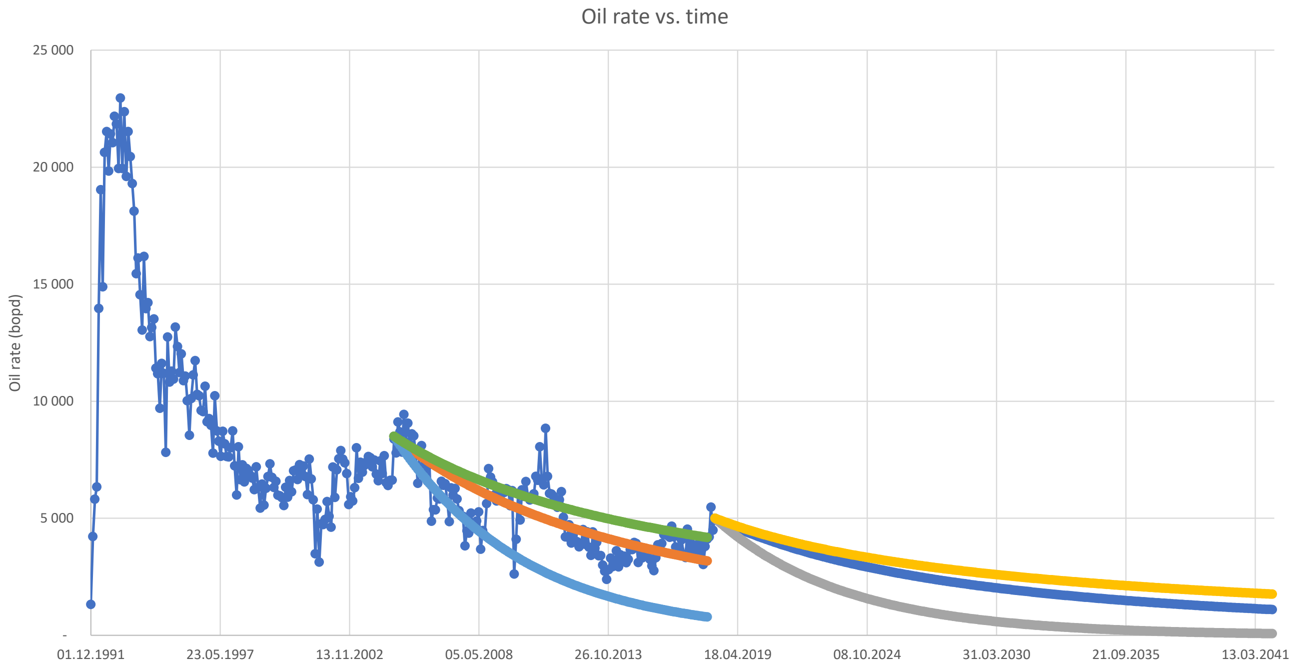


Figure 2.30 Tchendo (Senonian+Turonian).Technical oil volumes from DCA
The base case decline curve has a b exponent of 0.5 (blue line). This corresponds to the orange match line. The curves are thus displayed parallel to each other. The match line is displayed purely to show how the prediction corresponds to the history. Likewise for the high and low cases. Note that the low case match line is somewhat lower than the corresponding history. This is to honor the results from the other DCA methods more correctly.

Table 2.15 Technical oil volumes with different DCA methods

	Oil rate vs. time, entire reservoir	Oil rate vs. time split between Senonian and Turonian	Oil rate vs. cumulative oil	Water cut vs. cumulative oil
Oil volume end 2041	21	23	8	11

The same exercise on Senonian and Turonian separately, gave a combined, technical oil volume of 23 MMbbl. Method 3) and 4) gave a 50 % lower oil volume, see Figure 2.31 for water cut vs. cumulative oil. To honour the low volumes with method 3) and 4), the low case (11 MMbbl) is set much lower than the upside (25 MMbbl), yielding an uncertainty range of approx. - 50 % and + 20 %.

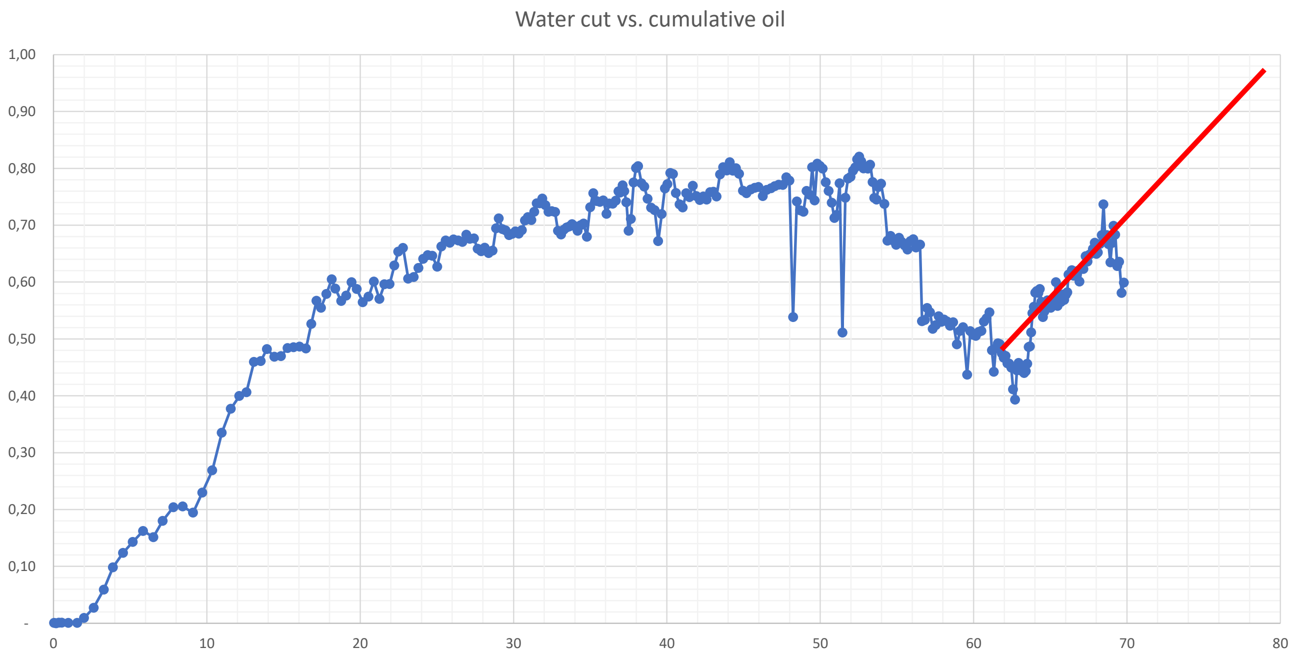


Figure 2.31 Tchendo. Water cut vs. cumulative oil
Extrapolating the water cut up to 98 % gives a technical oil volume of 11 MMbbl

Recovery Factors
The overall recovery factors for oil from existing wells are given in Table 2.8.

Table 2.16 Tchendo recovery factors

	Oil RF by 31.12.2017 (%)	Oil RF at 31.12.2041 (%)
Senonian	1.3	2.5
Turonian	26	35
Cenomanian	56	56
Sum	6.7	8.8

Reserves and Contingent Resources Classification
The production profiles used as the basis for reserves for Tchendo are shown in Appendix A2 - Production Profiles. The underlying reserves are classified according to SPE-PRMS as follows:

- "On production": Production from existing wells.

The reserves category also include the regularly maintenance and workover on the field that is part of the long term plan and is considered as the daily management. This is indirectly incorporated in the decline curve analysis when estimating future production, as this is also done in the history.

Back in 2016 the operator Total made plans of increasing the oil volumes by 37 MMbbl, split into two phases, by drilling of 17 producers and 3 water injectors. The phases comprised also a full field development of Senonian, with a very high STOIIP. Since then the operatorship has been changed. Petronor, licence partner, has proposed new plans for increasing the producible volumes. A preliminary plan is as follows:

- 3 workovers in 2019
- 4 infill wells + 3 water injectors in 2020 - 2021, targeting particularly Turonian
- 4 infill wells (horizontal wells w/fracs in Senonian?) in 2022 - 2023

The suggested plan looks feasible. However, both the Turonian and in particular Senonien has low recoveries to date. The Senonien has additionally a significant STOOIP which should be targeted with more advanced wells and possibly modern stimulation techniques. These projects need more studies and detailing before they can be sanctioned, and as such they are currently classified as contingent resources; "Development Unclarified". Before being booked as reserves a development plan, positive economy, a commitment from the licence and relevant approvals from the authorities, are required.

AGR considers the 3 workovers planned for 2019 as part of the daily maintenance/management of the field. These volumes are thus already indirectly incorporated in the reserves by the DCA, and is not added to the contingent resources found in Table 2.19.

2.3.4 Recoverable Volumes

Reserves
The production profiles have been checked for economic cut-off using following assumptions, with PV Reference Date: 1.1.2018.

Table 2.17 Economic Assumptions

Economic Assumptions		
Oil Price	USD/bbl	70.0

The reserves are given in the table below. The cut-off year is defined as the last year with positive cash-flow based on cost profile see A3 - Cost Profiles. For all cases, the economic cut-off year is reached at the end of 2041.

Table 2.18 Tchendo gross reserves as of 1.1.2018

Reserves, AGR review	1P	2P	3P
Oil, MMbbl	10.63	20.84	25.08
Gas, BScf	3.72	7.29	8.78
NGL, MMboe	0.00	0.00	0.00
Total, MMboe	**11.29**	**22.14**	**26.64**

Contingent Resources
The contingent resources are given in the table below.

An explanation of contingent resources is given in chapter 2.2.3 Reservoir Engineering.

Table 2.19 displays the contingent resources for Tchendo. The 2C resources include two new producers commencing production during 2020 and two during 2021. At the same time two water injectors will be drilled in mid 2020 and one mid 2021, i.e. a total of three. We have no information about any estimated initial start rate for a future infill well for Tchendo. Nor have we any information whether the wells will be horizontal or vertical. As the injectors can support multiple wells, and if we assume the wells to be slanted, AGR have estimated the initial rate of each new producer to 800 bopd/well. The start rate is above the average of 300 bopd from a current producer in 2018 (only vertical). This estimation is uncertain, but probable. The same decline rate has been used for the 2C wells as for the 2P profile (same b exponent, but higher initial decline). The 3C resources includes four additional infill wells; two in mid 2022 and two in mid 2023. As no water injectors are drilled in conjunction with these wells and the fact that they are starting later in time (reservoir more water flooded), these wells are assumed with a start rate of 600 bopd/well. These four wells are set with the same deline rate as the 3P profile. For the 1C resources we have assumed that the start rate is slightly less than that of the 2C resources (700 bopd/w) for the four planned producers in 2020 and 2021 (includes also the three WI), and that they follow the 1P decline. The gas resources are estimate by multiplying the oil volume by the average GOR for the two last years.

Table 2.19 Contingent Resources Tchendo (100 %) verified by AGR as of 1.1.2018 - 31.12.2041

	Oil, MMbbl			Gas, BScf			Total, MMboe		
Gross	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Tchendo	5.6	10.8	17.8	2.0	3.8	6.2	6.0	11.5	19.0

2.3.5 Facilities Development

The Tchendo field facilities have been developed as seen in Figure 2.32 and consist of a single jacket well-head platform. Production started in 1991. Oil is exported to Denjo onshore terminal.

The field platform should have significant spare capacity with the current operations and coming production trends, as seen from the historical production curves.

The below wording is copied from the Tchibuela field facilities, but is mostly relevant for Tchendo field facilities as well.

AGR observations

- AGR has not seen any Design Basis document (including design capacities and - lifetime for structures / critical equipment) and would flag lifetime as a potential concern, especially with respect to corrosion issues.
- AGR has been told that the Operator have two workover units owned by themselves and subsequently AGR do support the relative active workover strategy.
- AGR has not seen any well slot overview and status and would flag that this could be a future challenge.
- AGR does expect that Perenco has withheld Totals ordinary operation-/maintenance activities and/or any own similar programs, as AGR has not seen these.
- AGR does find the 2018 CAPEX (cathodic protection, power generation update and sealine recovery) and the 2018 OPEX (mainly well workovers / new ESPs) to be realistic.
- AGR does support the cost figures being used in the economical analyses, benchmarking these with relevant in-house cost data.
- AGR has not seen any Risk (uncertainty) Management analyses and subsequent unified "top ten" Risks Matrix from OC-and TC meetings.

AGR conclusions

- AGR concludes that there is no technical showstoppers with respect to further production in the near future, however, AGR would alarm that design lifetime (and subsequent technical integrity status) for critical steel structures and - key equipment could be an area of concern in time (especially corrosion issues).
- AGR does support Petronor's aim to follow the operators activities closely and ensure that all measures are taken, which will increase the producibility of each field.
- AGR would recommend Risk Management as an value add system, especially in implementing Petronor's upside potentials and also highlighting critical downsides as Petronor see it.

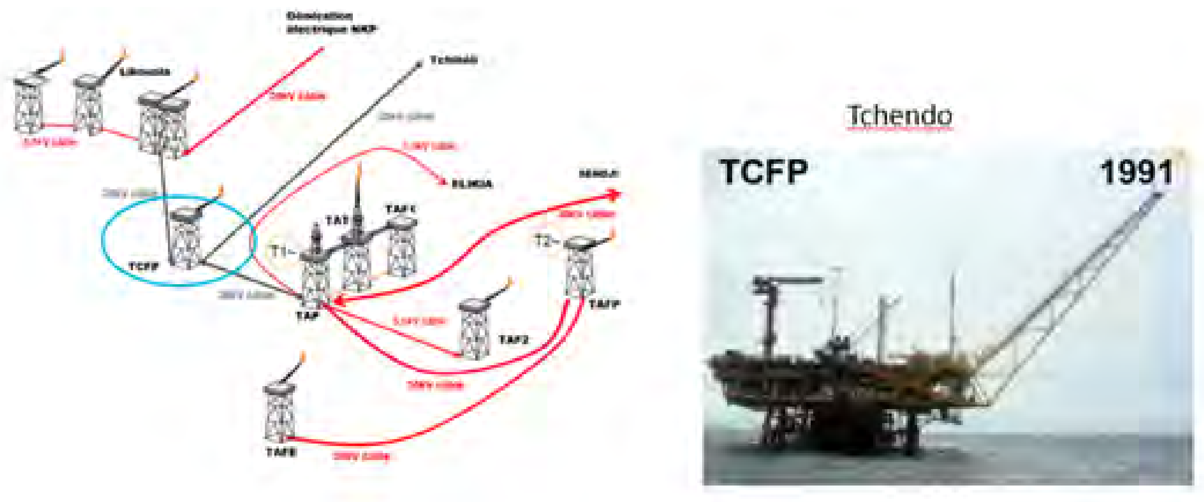


Figure 2.32 Tchendo. Facilities layout

2.4 Tchibeli

2.4.1 G&G

Geological Setting
A schematic crossection of the reservoir interval together with the depth map of the Albian top reservoir level is shown in Figure 2.33. The Tchibeli Field is a four way structural closure of the Albian formed as a turtle-back structure. The structure is cut by several northwest-southeast trending faults. The reservoir consists of shallow marine, high-energy oolitic/oncolytic carbonate shoal deposits of Albian age. The RCT reservoir is a carbonate and the RSCT reservoir is a mix between silt and carbonate. The field is appraised by three exploration wells and further information has been gained by the seven development wells.

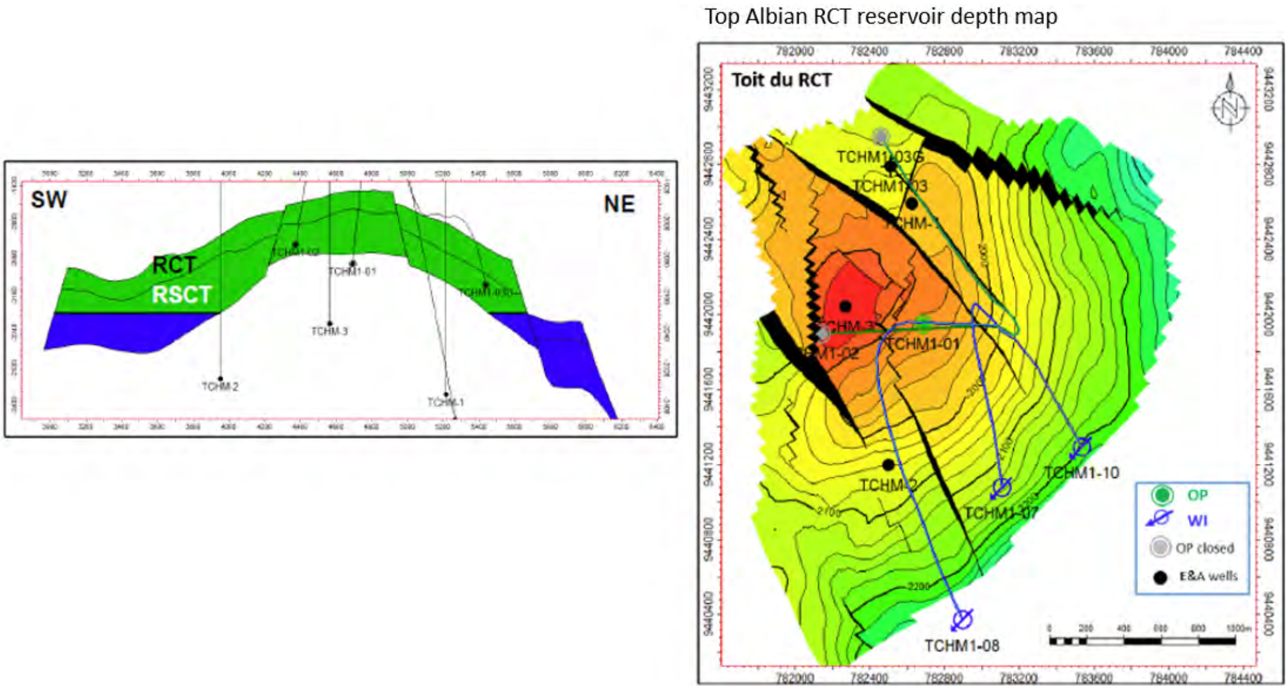


Figure 2.33 Tchibeli Albian.Top reservoir depth and schematic crossection of the reservoir

Reservoir Properties
Reservoir properties in Tchibeli are summarized in Table 2.20. AGR has reviewed the log data provided for the Albian in Tchibeli wells. Accordingly, full set conventional well logs are acquired for almost the entire Albian section. In general quality of the well logs and petrophysical results is good. Based on petrophysical interpretation results the "Albian Top RCT" and "Albian Top RSCT" zones are the main oil bearing intervals.

Average permeability is around 160 mD.

Table 2.20 Reservoir parameters for the Tchibeli field. From AGR petrophysical evaluation review

Well	Zone	Thickness (m)	net/gross	Porosity	Av Vcl	Sw (in HC-zone)
TCHM-1	Albian	98	0.45	0.209	0.05	0.17
TCHM-2	Albian	137	0.14	0.147	0.05	0.30
TCHM-3	Albian	135	0.53	0.217	0.05	0.11
TCHM1-01	Albian	100	0.43	0.186	0.09	0.12
TCHM1-02	Albian	155	0.52	0.213	0.06	0.10
TCHM1-03	Albian	147	0.52	0.209	0.07	0.09
TCHM1-07	Albian	702	0.70	0.191	0.08	0.18
TCHM1-08	Albian	406	0.70	0.217	0.04	0.14
TCHM1-10	Albian	517	0.38	0.187	0.08	0.35

Seismic Data

The 2006 survey is a Pre Stack Time Migrated data set. The seismic data is of fair to good quality, though slightly noisy. In addition, a survey from 2014 is found in the Petrel project. The two surveys are slightly skewed to each other (Figure 2.34). The 2014 survey has been cropped to barely cover the field. The title of the data indicates that it is Pre Stack Depth migrated data presented in depth and time. The quality of the 2014 seismic is good.

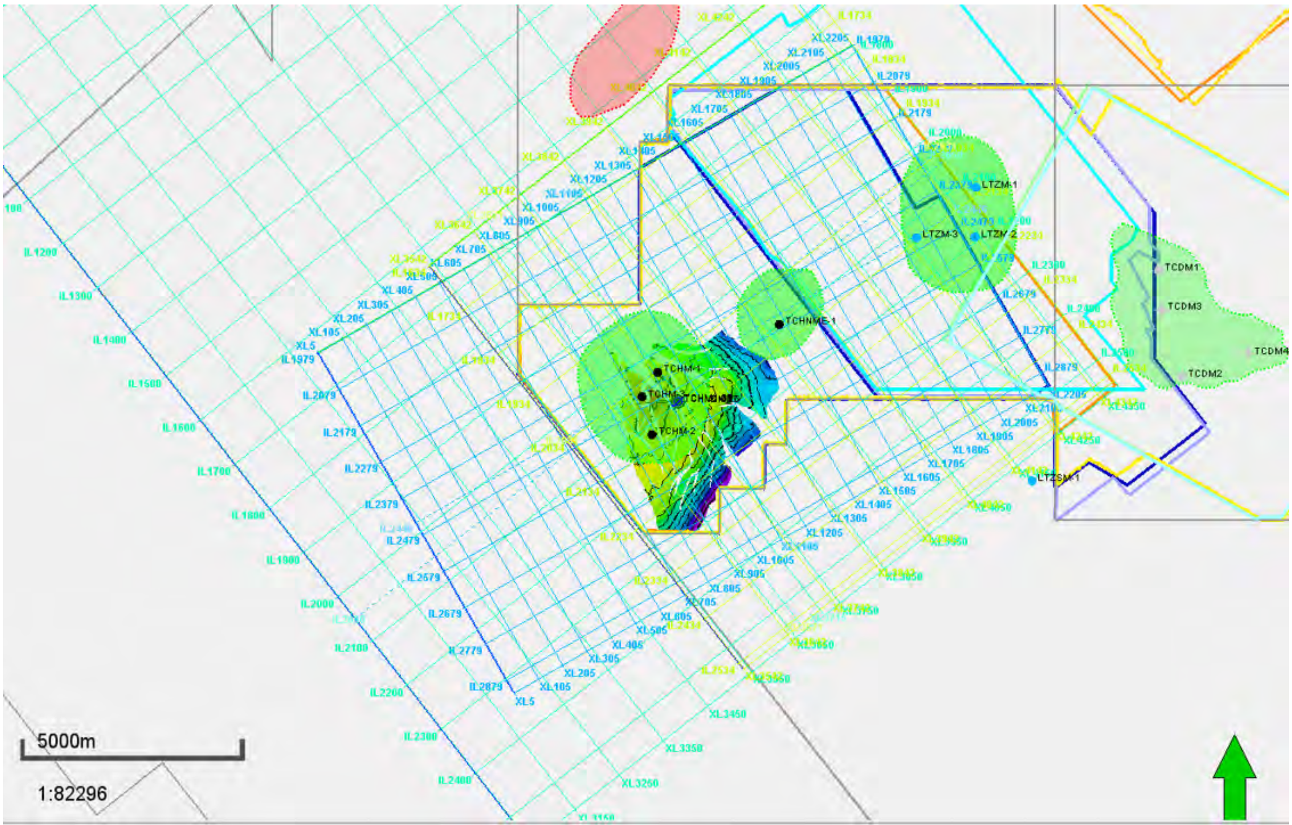


Figure 2.34 Tchibeli. Seismic data coverage

No seismic well tie has been found within the documentation provided by Perenco or the client.

Horizons found in the project are in Time and Depth. They may have been interpreted on the 2014 survey. The interpretation is ok but inaccurate (Figure 2.35).

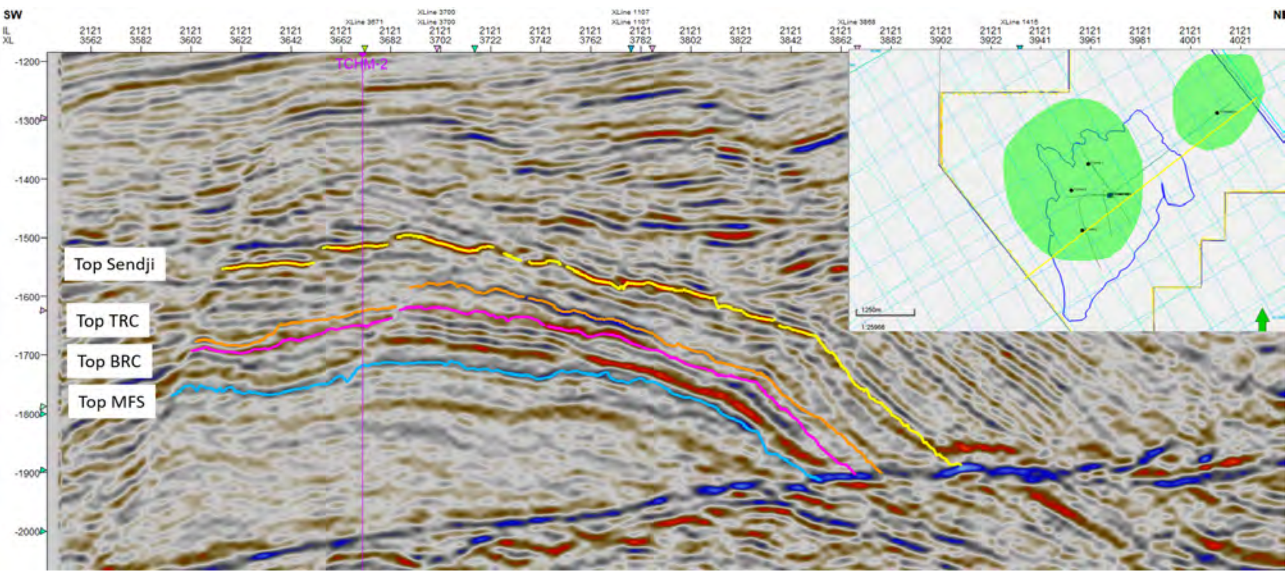


Figure 2.35 Seismic Interpretation over Tchibeli

Apparently no new depth grids have been produced by Perenco (the Operator). The Perenco interpretation is nearly a copy of the Total interpretation. The 2015 depth grids from Total (previous operator) model do not match the depth seismic very well (Figure 2.36).

Three horizons are presented in the depth random line: Top Reservoir - Orange, Base Reservoir - Magenta and MFS 50 Base Res SC - light blue.

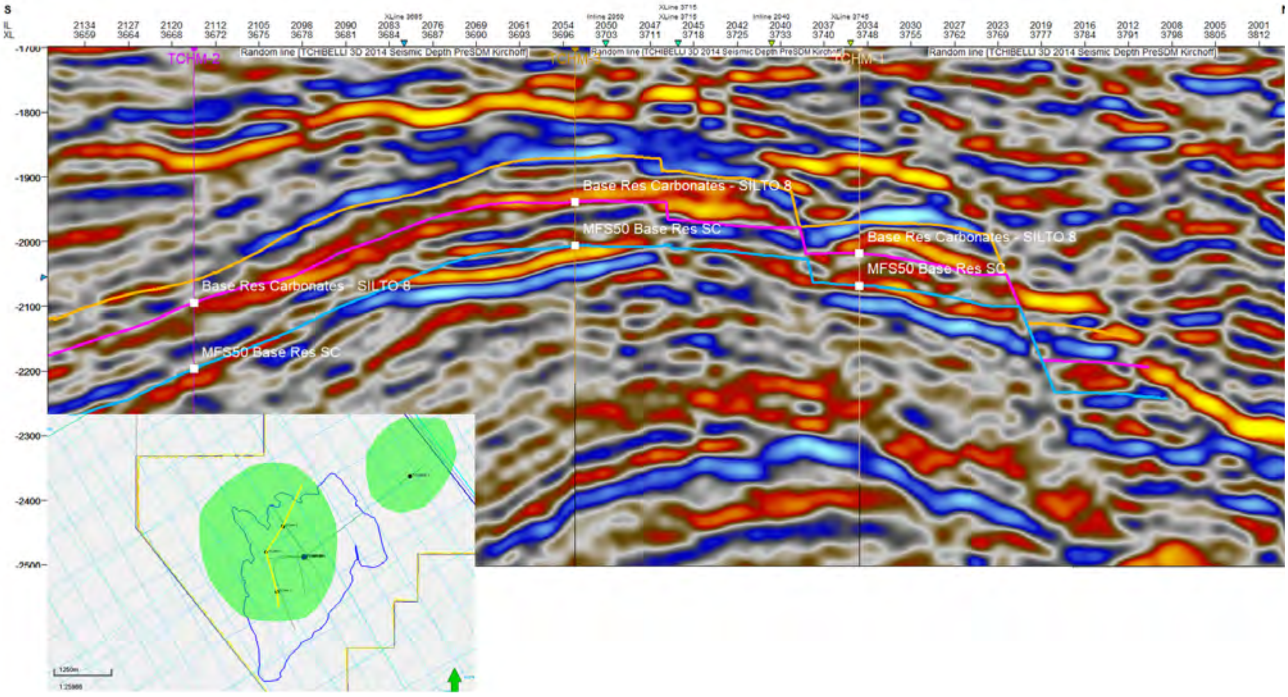


Figure 2.36 Tchibeli. Interpretation in depth mismatch to PSDM seismic.

Static Model
A full integrated study including updated seismic interpretation, petrophysics and structural/property modelling will be issued by Perenco mid 2019.

The 3D static model in the data room is built by Total in 2015. The structural framework is based on faults and surfaces interpreted on the PSDM data set from 2014. There are three main zones in the 2015 model which are roughly corresponding to the RCT/RSCT zones in Figure 2.33.

There is no facies model. Figure 2.37 illustrates the net/gross, porosity, permeability and water saturation in the model. In this field the effective porosity/SW system has been modelled. The best properties are found on the crest of the structure in the middle zone. The OWC is set to 2198 mTVDSS. There is good correlation between net/gross and PHIE and the modelled PHIE are in line with the logs (Figure 2.38). The SWE property is very coarse, with a height function towards the OWC.

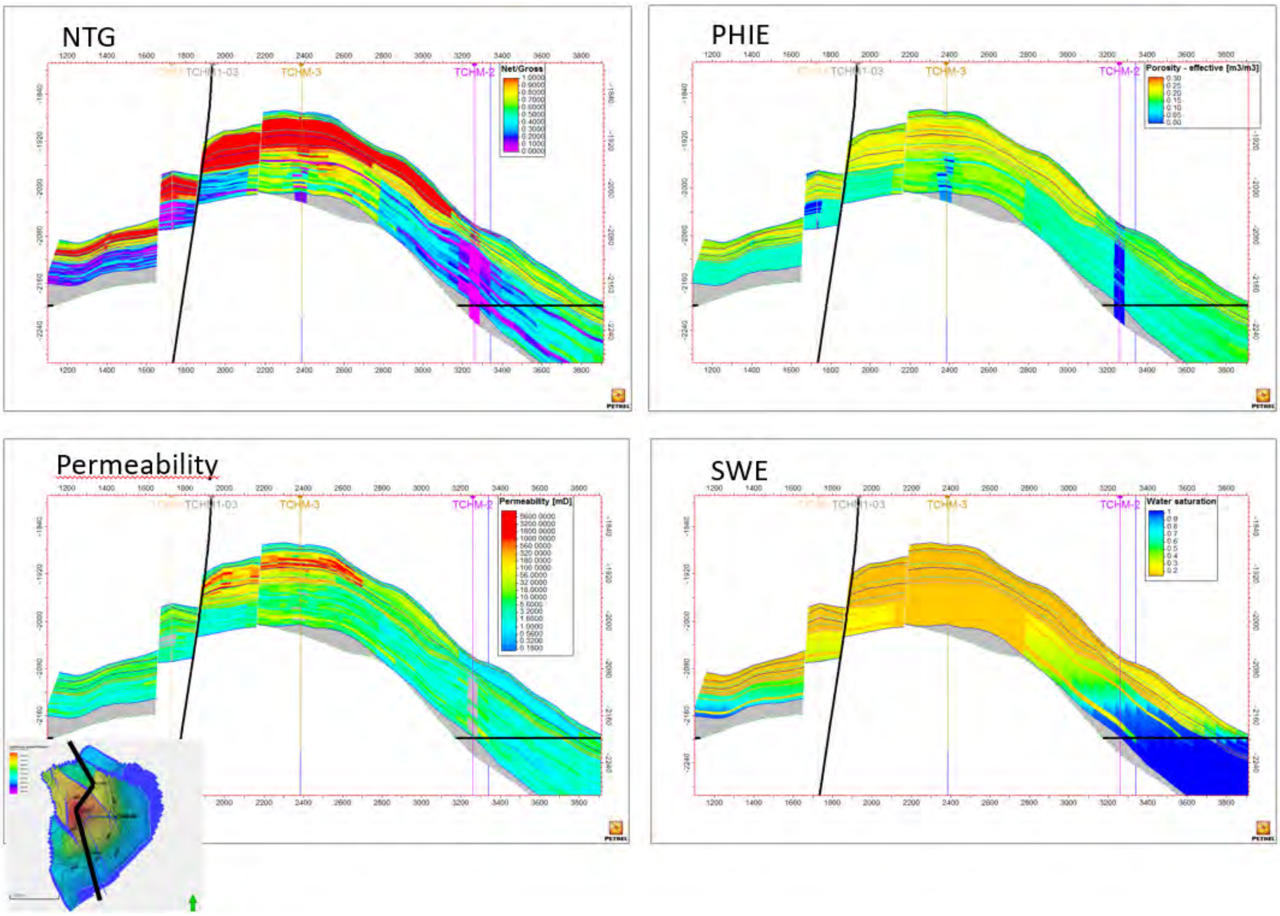


Figure 2.37 Tchibeli Albian. Crossections through the static model
From Petrel project, 3D static model, Total 2015

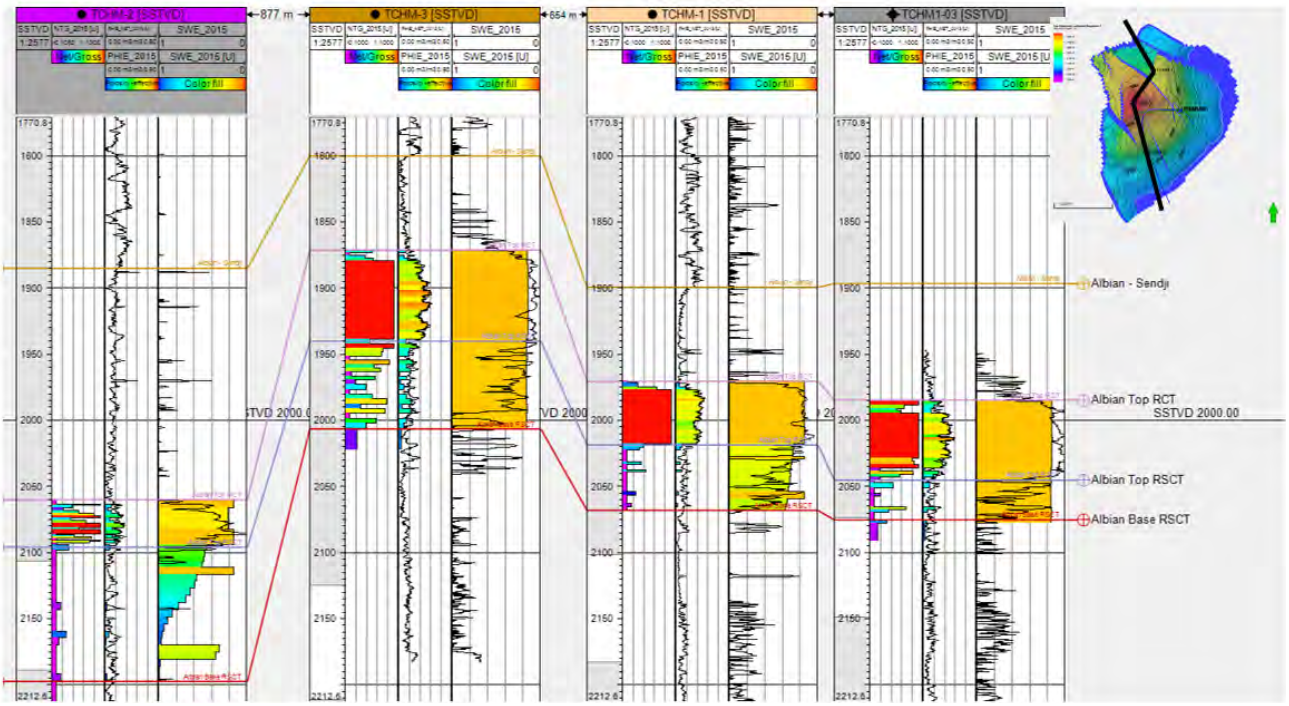


Figure 2.38 Tchibeli Albian. Logs and reservoir properties
From Petrel project, 3D static model, Total 2015

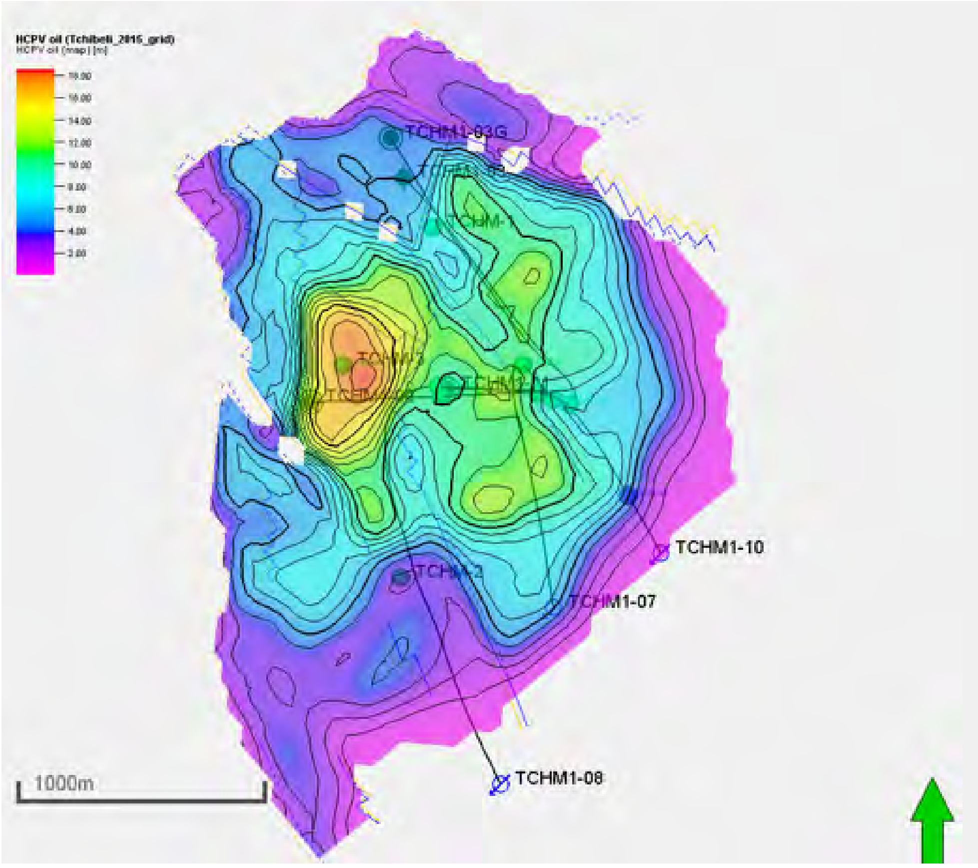


Figure 2.39 Tchibeli Albian. HCPV map
From Petrel project, 3D static model, Total 2015

STOIIP and average reservoir properties in the Albian 2015 static model is shown in Table 2.21.These numbers are slightly lower than the base case reported by Perenco in 2018. The average net/gross and porosity parameters are on the pessimistic side compared to AGR petrophysical evaluation, while oil saturation seems to be reasonably in line with AGR or underestimated.

It is AGR's view that the Total 2015 static modelling has been performed according to industry standard and with adequate quality.

Table 2.21 Tchbeli Albian STOIIP and reservoir properties in the Total 2015 static model

	Volumetrics					Average reservoir properties in the hydrocarbon zone		
Reservoir	**Gross rock volume (*10^6 m^3)**	**Net volume (*10^6 m^3)**	**Pore volume (*10^6 m^3)**	**HCPV oil (*10^6 m^3)**	**STOIIP (MMbbl)**	**net/gross**	**Porosity**	**Sw**
Albian RCT	178.2	135.6	25.23	20.46	94.0	0.76	0.19	0.19
Albian RCST	243.3	90.5	11.06	7.46	34.2	0.37	0.12	0.33
Total Albian	**421.5**	**225.2**	**36.28**	**27.92**	**128.2**	**0.54**	**0.16**	**0.23**

The latest seismic surfaces from Perenco were provided to AGR. AGR compared the 2015 model with the Albian top reservoir map (Figure 2.40) and the trend is that the flanks in the new interpretation are deeper and parts of the crest are shallower than the 2015 model from Total. AGR made a quick rebuild of the structural framework with the 2018 maps which gave an approximate 10% decrease of gross rock volume.

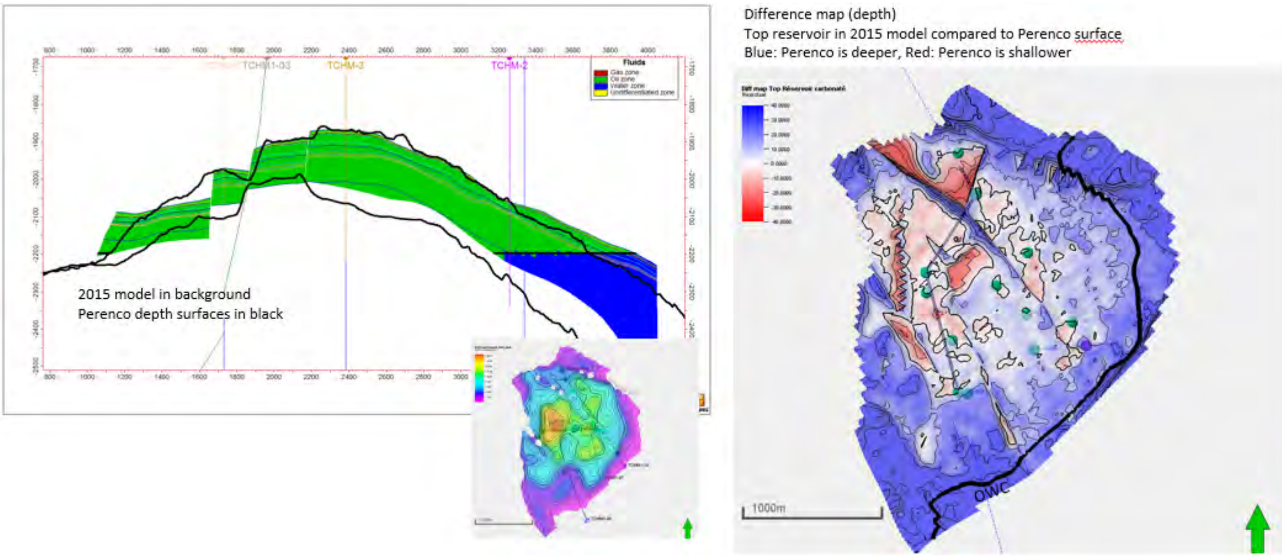


Figure 2.40 Tchibeli. Comparison of 2015 Total model to Perenco 2018 depth surfaces

2.4.2 STOIIP/GIIP

The STOIIP for Tchibeli field is listed in Table 2.22

The base STOIIP estimates for the Albian were presented by Perenco in the OCM meeting from June 2018 and this number is reasonable given the seismic interpretation, static model and documentation available to AGR. No uncertainty span has been reported by Perenco, but in a reservoir modelling report from Total 2011 a range of low/mid /high of 124/138/156 MMbbl was given based on an history matched reservoir model. AGR has simply applied the -10%/+15% uncertainty span around the base case STOIIP value as in the 2011 report.

Table 2.22 Tchibeli in-place volumes

		STOIIP (MMbbl)		
Field	**Reservoir**	**Low**	**Base**	**High**
Tchibeli	Albian	120	134	155

2.4.3 Reservoir Engineering

Reservoir
AGR has evaluated the resource numbers and profiles in relation to the definition of the various resource classes. The main sources of data are the presentations given by Petronor and the former operator Total, in addition to the historical production data. There exist also a dynamic Eclipse model from 2014 and a static Petrel model, modified in February 2017 from an older version.

Tchibeli field was discovered in 1986 and came on stream in year 2000. Peak production of 13 000 bopd was reached after 2 months of production, and has since then been on decline, see Figure 2.41. In total three producers have been drilled, and all three wells are still producing with a current rate of 2 800 bopd. Water breakthrough occurred after approx. two years, and is now 90 % in two of three wells. In the third well the water cut is around 50 %. Two of three operating water injectors injects around 22 000 bopd. Regularity is around 96 %, and since mid 2017 the production has slightly increased.

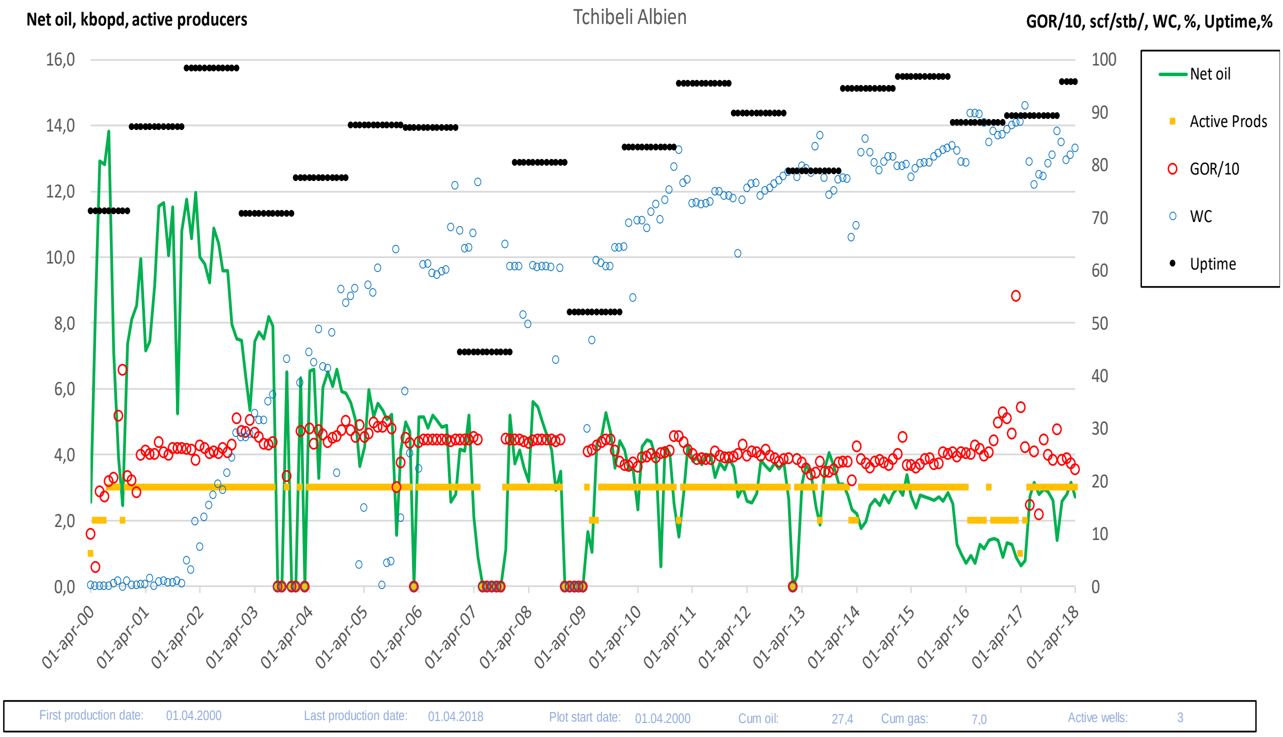


Figure 2.41 Tchibeli. Historic oil production rate
Oil production from April 2000. Also displayed is water cut, no. of active producers, GOR and uptime

The water depth is 112 meter with a reservoir depth of 2000 meter. The field consists of two disconnected Albian reservoirs, with a porosity of 21 % and permeability of 160 mD. The oil density is 38 degrees API.

<u>Status</u>

The oil production has increased since Perenco took over operatorship in 2017. This has been done by well workovers (ESP) and platform debottlenecking.

Production Forecasting
AGR has used the historical production rates from the existing wells as the main source for prediction. The dynamic Eclipse model is of older vintage, and has thus not been used.

The three different decline curve analysis techniques that have been used on the existing wells, are as follows:

1. Oil rate versus time for the entire reservoir
2. Water cut versus accumulated oil
3. Oil rate versus accumulated oil

Table 2.23 Technical oil volumes with different DCA methods

	Oil rate vs. time	Oil rate vs. cumulative oil	Water cut vs. cumulative oil
Oil volume end 2041 (MMbbl)	12	10	8

Figure 2.42 and Figure 2.43 shows two different techniques of estimating the future production based on the existing wells. Method 1) is the main technique for estimating the future production in this study, with the other methods as supportive. The low case of the rate vs. time plot corresponds to 8 MMbbl, corresponding to the result from method 2). The high case is taken from the most optimistic "match curve" in Figure 2.42. The range from the base case is -28 % and +24 %.

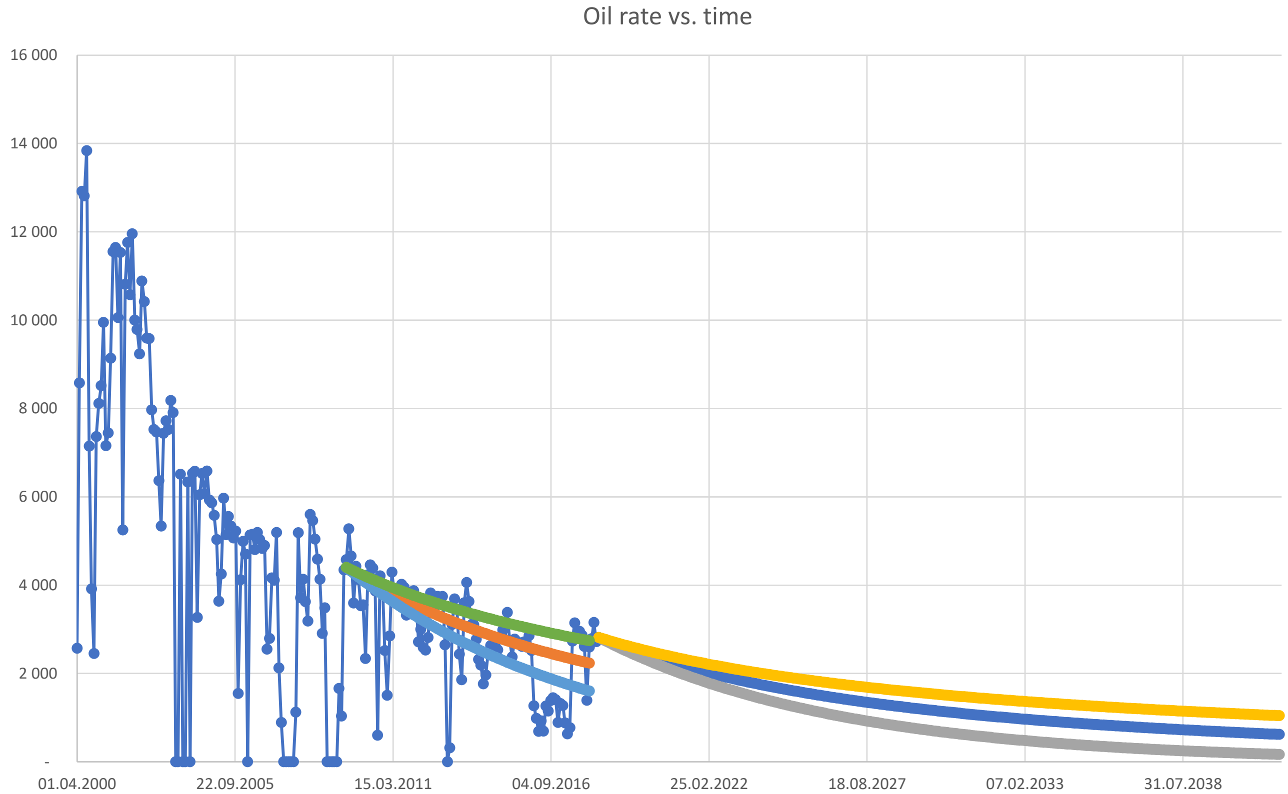


Figure 2.42 Tchibeli. Decline curve analysis from historic oil production rate
The base case prediction (blue line) is base on a b exponent of 0.5, as the corresponding match curve (orange). These curves are displayed parallel to each other. The match line is superimposed the historic rate as a visualization how the estimated future production would look like compared to the history. The same is the case for the high and low case.

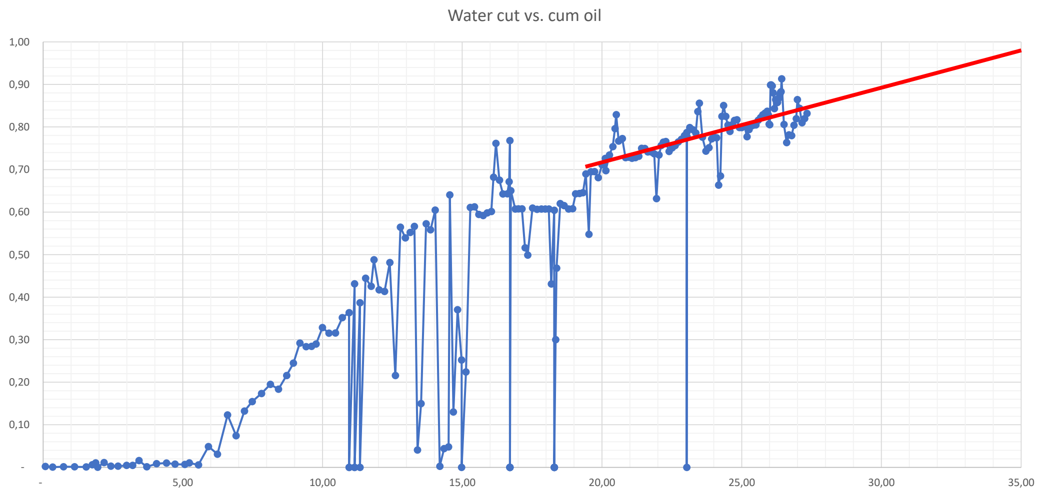


Figure 2.43 Tchibeli. Water cut vs. cumulative oil
By extrapolating the water cut to 98 % water, it is possible to estimate the future oil volume.

Recovery Factors
The overall recovery factors for oil from the three existing wells, are given in Table 2.8.

Table 2.24 Tchibeli recovery factors

	Oil RF by 31.12.2017 (%)	Oil RF by 31.12.2041 (%)
Albian reservoir	20	29

Reserves and Contingent Resources Classification
The production profiles used as the basis for reserves for Tchibeli are shown in Appendix A2 - Production Profiles. The underlying reserves are classified according to SPE-PRMS as follows:

- "On production": Production from existing wells.

Back in 2016 the previous operator Total made plans for increasing the oil volumes by 6 MMbbl in a single phase of development; two producers and five water injectors. Petronor, licence partner, has proposed new plans for increasing recovery. A preliminary plan is as follows:

- Debottlenecking
- 2 infill wells + 1 water injectors in 2020 - 2021
- 2 infill wells in 2022 - 2023

The suggested plan looks feasible. However, these projects need more studies and detailing before they can be sanctioned, and as such they are currently classified as contingent resources; "Development Unclarified". Before being booked as reserves a development plan, positive economy, a commitment from the licence and relevant approvals from the authorities, are required.

2.4.4 Recoverable Volumes

Reserves
The production profiles have been checked for economic cut-off using following assumptions, with PV Reference Date: 1.1.2018.

Table 2.25 Economic Assumptions

Economic Assumptions		
Oil Price	USD/bbl	70.0
Gas Price	USD/mscf	6

The reserves are given in the table below. The cut-off year is defined as the last year with positive cash-flow based on cost profile see A3 - Cost Profiles. For all cases, the economic cut-off year is reached at the end of 2041.

Table 2.26 Tchibeli gross reserves as of 1.1.2018

Reserves, AGR review	1P	2P	3P
Oil, MMbbl	8.44	11.76	14.56
Gas, BScf	2.32	3.23	4.00
NGL, MMboe	0.00	0.00	0.00
Total, MMboe	**8.86**	**12.33**	**15.27**

Contingent Resources
The contingent resources are given in the table below.

An explanation of contingent resources is given in chapter 2.2.3 Reservoir Engineering.

Table 2.27 displays the contingent resources for Tchibeli. The 2C resources include one new producer commencing production during 2020 and one during 2021. At the same time one water injector will be drilled in mid 2020. We have no information about any estimated initial start rate for a future infill well for Tchibeli. Nor have we any information if the wells will be horizontal or vertical. As the injector can support multiple wells, and if we assume the wells to be slanted, AGR have estimated the initial rate of each new producer to 1000 bopd/well. This is above the average of 900 bopd from the three current producers in 2018 (only vertical). The same decline rate has been used for the 2C wells as for the 2P profile (same b exponent). The 3C resources adds additionally one new infill well in mid 2022 and one new in mid 2023. As no water injectors are drilled in conjunction with these wells and the fact that they are starting later in time (reservoir more water flooded), they are assumed with a start rate of 600 bopd/well. These two wells are set with the same deline rate as the 3P profile (same b exponent). For the 1C resources we have assumed that the start rate is slightly less than that of the 2C resources (700 bopd/w) for the two planned producers in 2020 and 2021 (includes also the WI), and that they follow the 1P decline. The gas resources are estimate by multiplying the oil volume by the average GOR for the two last years.

Table 2.27 Contingent Resources Tchibeli (100 %) verified by AGR as of 1.1.2018 to 31.12.2041

	Oil, MMbbl			Gas, BScf			Total, MMboe		
Gross	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Tchibeli	4.0	6.7	11.4	1.1	1.9	3.1	4.1	7.1	12.0

2.4.5 Facilities Development

The Tchibeli field facilities have been developed as seen in Figure 2.44 and consists of a single jacket well-head platform. Production started in 2000. Oil is exported to the Nkossa field.

The field platform should have significant spare capacity with the current operations and coming production trends, as seen from the historical production curves.

The below wording is copied from the Tchibouela field facilities, but is mostly relevant for Tchibeli field facilities as well.

AGR observations

- AGR has not seen any Design Basis document (including design capacities and - lifetime for structures / critical equipment) and would flag lifetime as a potential concern in a twenty years aspect.
- AGR has been told that the Operator have two workover units owned by themselves and subsequently AGR do support the relative active workover strategy.
- AGR has not seen any well slot overview and status and would flag that this could be a future challenge.
- AGR does expect that Perenco has withheld Totals ordinary operation-/maintenance activities and/or any own similar programs, as AGR has not seen these.
- AGR does find the 2018 CAPEX (cathodic protection,power generation update and sealine recovery) and the 2018 OPEX (mainly well workovers/ new ESPs) to be realistic.
- AGR does support the cost figures beeing used in the economical analyses, benchmarking these with relevant inhouse cost data.
- AGR has not seen any Risk (uncertainty) Management analyses and subsequent unified "top ten" Risks Matrix from OC-and TC meetings.

AGR conclusions

- AGR concludes that there is no technical showstoppers with respect to further production in the near future, however, AGR would alarm that design lifetime (and subsequent technical integrity status) for critical steel structures and - key equipment could be an area of concern in time (especially corrosion issues).
- AGR does support Petronor's aim to follow the operators activities closely and ensure that all measures are taken, which will increase the producibility of each field.
- AGR would recommend Risk Management as an value add system, especially in implementing Petronor's upside potentials and also highlighting critical downsides as Petronor see it.

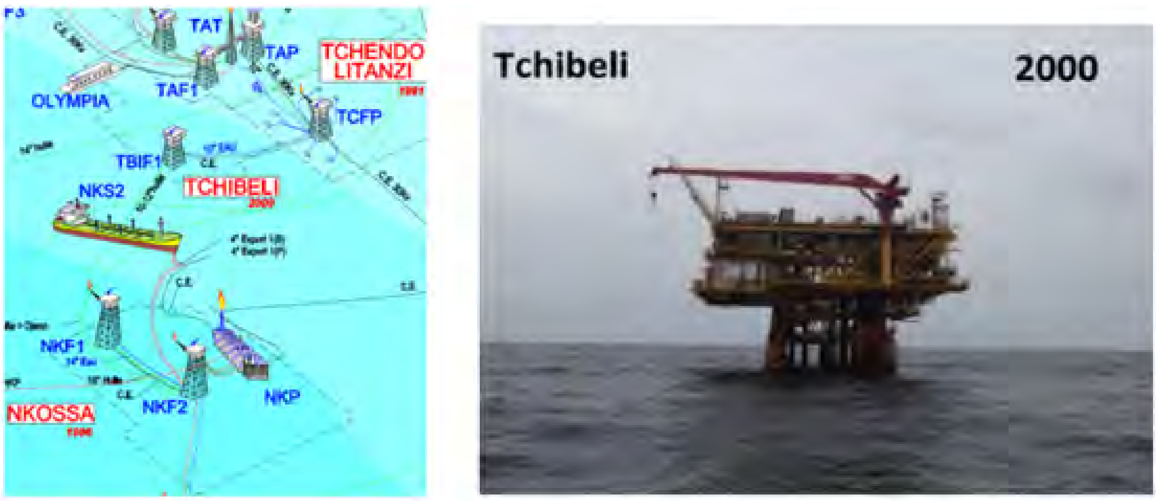


Figure 2.44 Tchibeli. Facilities layout

2.5 Litanzi

2.5.1 G&G

Geological Setting
The Litanzi Field is located north-east of the Tchibeli field and is producing from the Albian reservoir. A schematic crossection over the Litanzi field with a profile through the reservoir interval together with the depth map of the Albian R3 top reservoir level is shown in Figure 2.45. The structure is an anticline related to listric faulting towards the west and the field consists of several segments bounded by NNW-SSE trending faults. The field is appraised by four exploration wells and further information has been gained by the production/injector pair. The Albian consist of two separate intervals, R2 and R3, and the reservoir rock is mixture of carbonate, silt and sand. R3 is developed while R2 has poorer reservoir quality and is not developed.

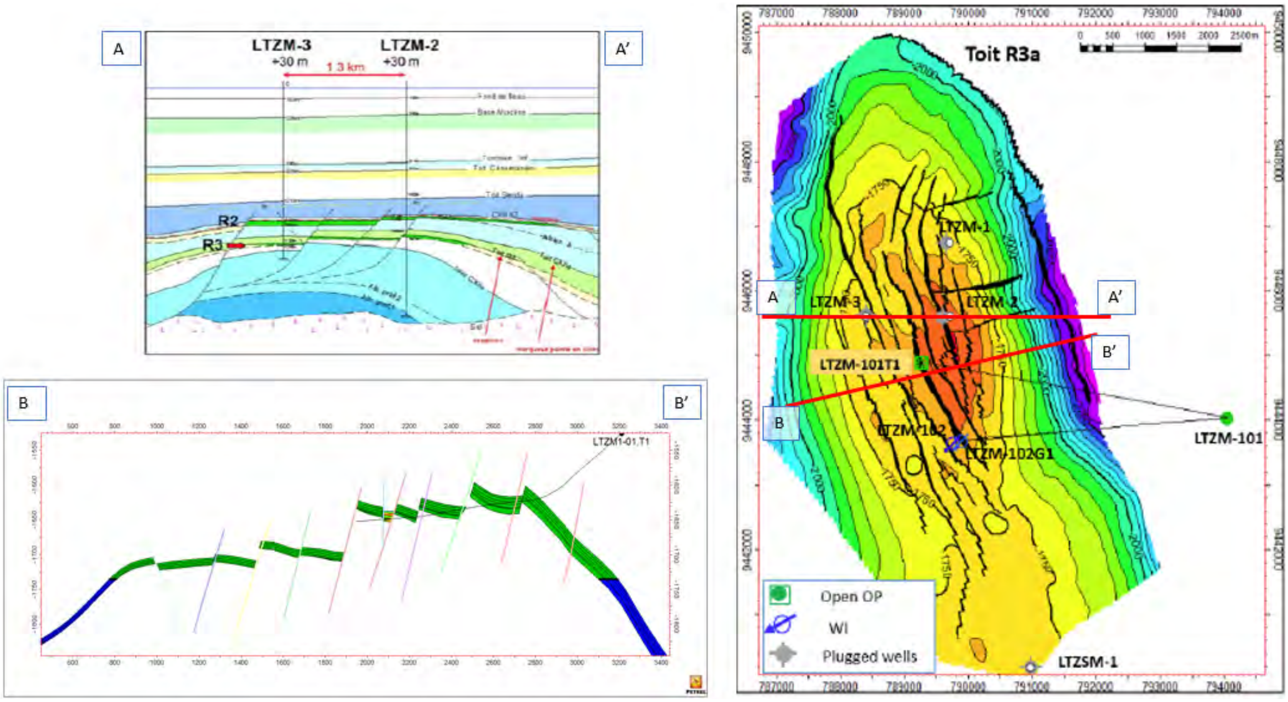


Figure 2.45 Litanzi Albian. Top reservoir depth map and schematic crossection of the reservoir

Reservoir Properties
Reservoir properties in Litanzi are summarized in Table 2.28. AGR has reviewed the log data provided for the Albian in Litanzi wells. Accordingly, full set conventional well logs are acquired for the entire Albian section. In general quality of the well logs and petrophysical results is good. Based on petrophysical interpretation results the "Albian R3" zone is the main oil bearing interval.

Table 2.28 Reservoir parameters for the Litanzi field. From AGR petrophysical evaluation review

Well	Zone	Thickness (m)	net/gross	Porosity	Av Vcl	Sw (in HC-zone)
LTZM-1	Albian R3	29.1	0.84	0.174	0.02	0.37
LTZM-2	Albian R3	24.5	0.86	0.193	0.03	0.19
LTZM-3	Albian R3	12.9	0.91	0.179	0.01	0.57
LTZSM-1	Albian R3	18.5	0.90	0.216	0.02	-

Seismic Data
According to material from Total, two surveys were acquired over Litanzi, one by PGS in 1996 and one by CGG in 2001 (Figure 2.46). PSTM was performed on the 2001 3D data set in 2006(5) by Western Geco and further processing was applied in 2010 (statics correction and a new PSTM by CGGV).

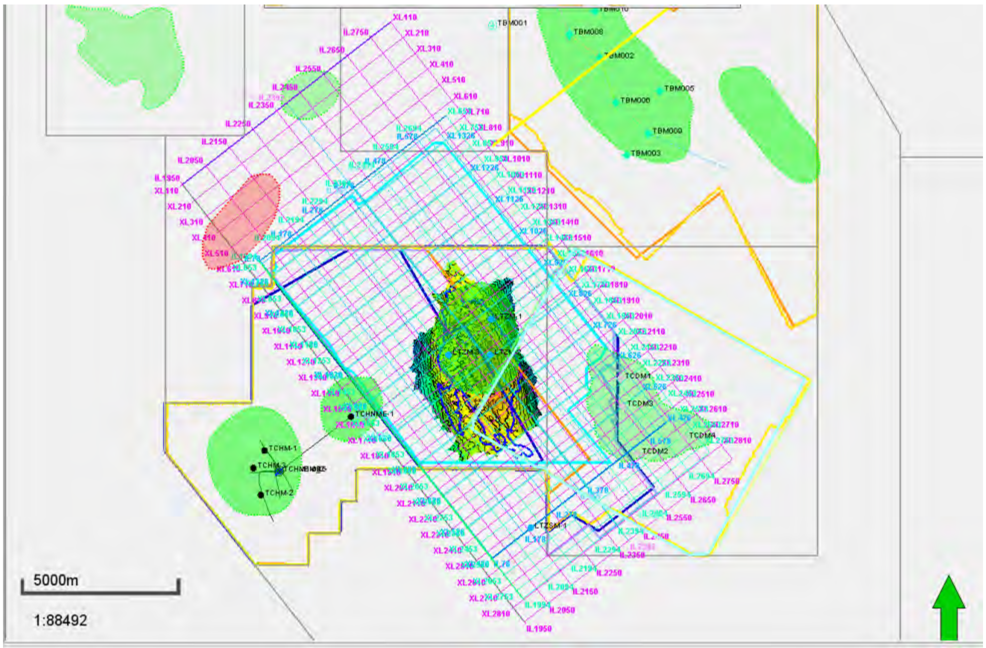


Figure 2.46 Litanzi. Seismic coverage with reservoir map.

The seismic data is rather poor over the Litanzi field. Three versions were presented; 1996. reprocessed 2005 and 2010. The top of the reservoir is highly effected by multiples (1996). The two reprocessing attempts have partially remove the multiples. But the data is still rather poor, (Figure 2.47).

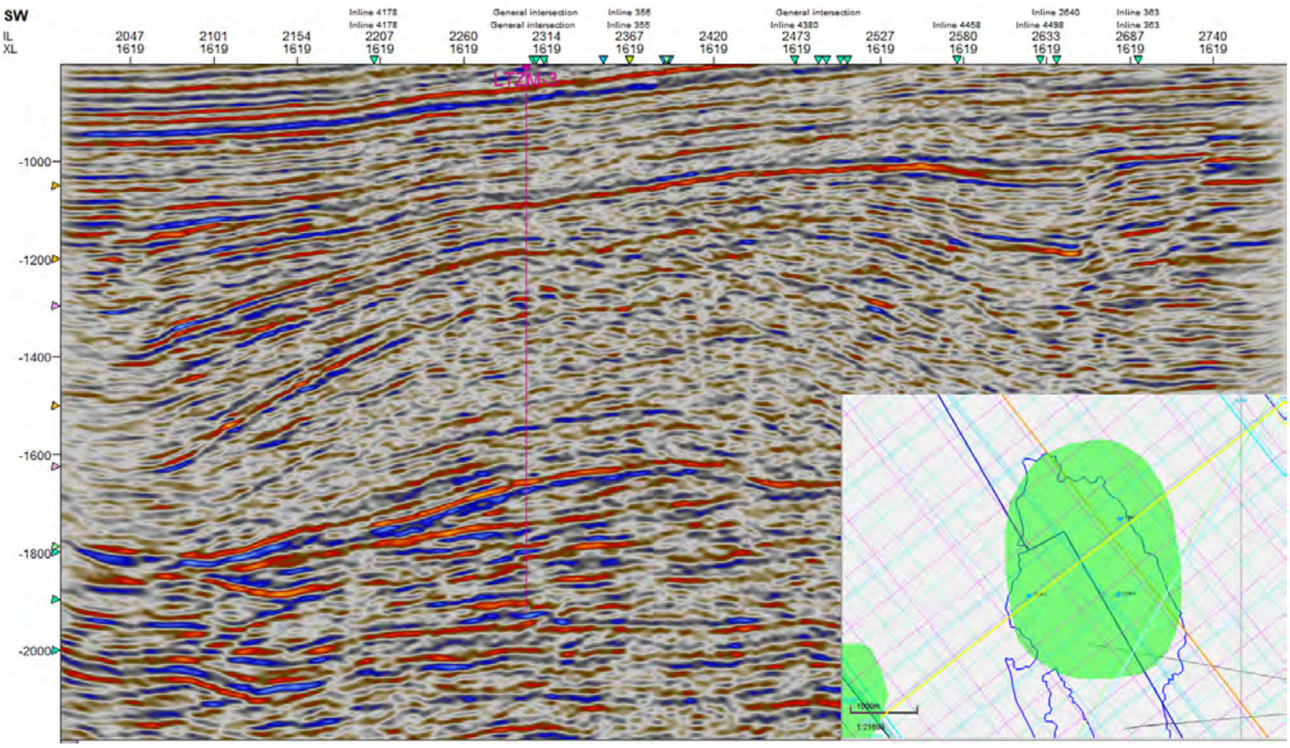


Figure 2.47 Litanzi. 2010 seismic through well LTZM-3

The working project contains no time-depth information though Total has produced a report for the Litanzi field seismic well ties which included the four exploration wells. The well seismic ties look good in the report. If the interpretation produced by the previous operator was with these well ties then it can be assumed that their interpretation at the well locations are good. The latest work from Perenco does not indicate any seismic well tie was performed.

The original interpretation is not available in the project. Gridded surfaces are present in the interpretation project. Based on the gridded surfaces the seismic interpretation of the reservoir is not very accurate as is the interpretation of the faults. Based on the difference in interpretations between Total and Perenco it is very uncertain what Perenco did for the seismic well tie. Neither interpretation is very good, though the Total interpretation is correlated to the wells. Generally the seismic interpretation for the reservoir is rather poor even in light of the poor seismic data quality.

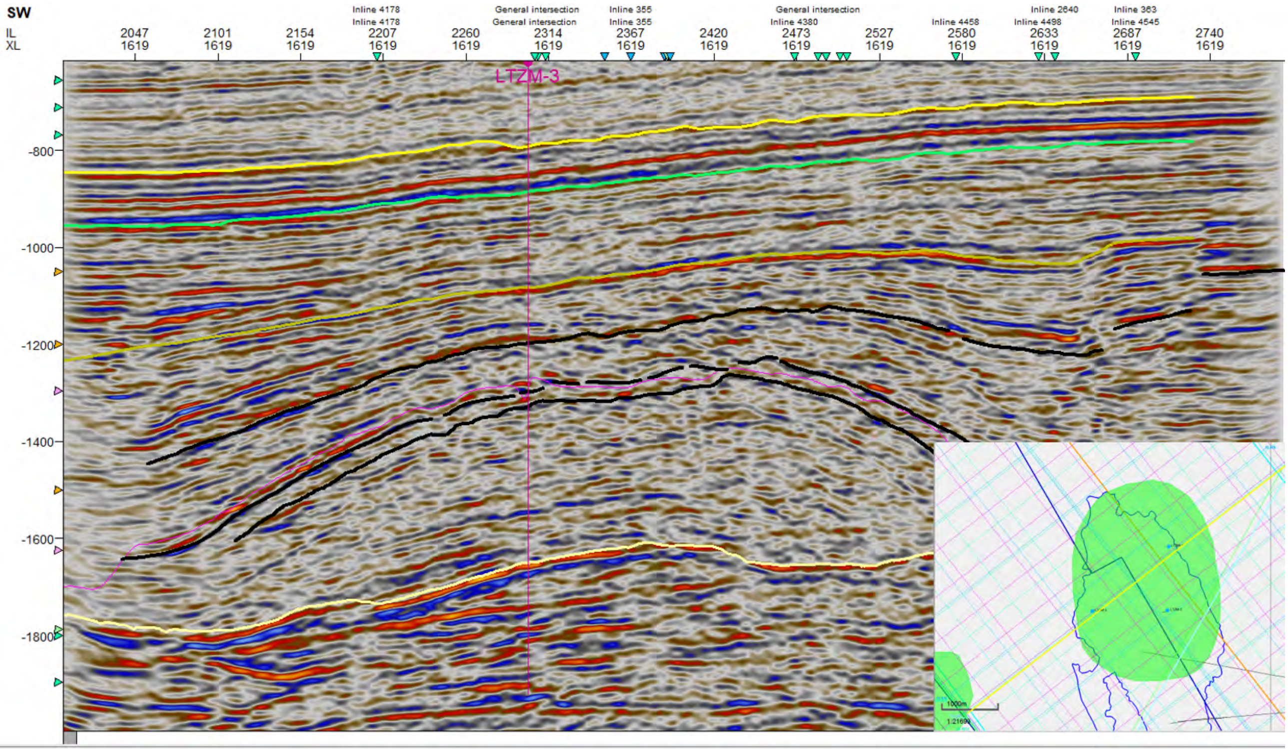


Figure 2.48 Seismic through well LTZM-3 with interpretation from Total and Perenco
Perenco: Top Senon dark magenta
Top Turo yellow
Top Ceno green
Top Albian peak olive green
Top R3 magenta
Top Salt light yellow
Total: MFS 50 upper black
Top CXIIa middle black
TOIT RS lower black

Static Model

A full integrated study including updated seismic interpretation, petrophysics and structural/property modelling will be issued by Perenco end 2018.

The 3D static model in the data room for the Albian R3 is built by Total in 2009. It is built upwards from one seismic surface of Base R3 within a fault model, probably based on the 2005 seismic data. The fault model looks very distinct, but information about original interpretation and depth conversion is not available. As mentioned above there is an uncertainty related to seismic interpretation of the thin faulted reservoir.

The Albian R3 is divided into three subzones each divided into a poorer and a better reservoir quality layer. A facies model is included with two rock types showing high porosity and permeability and two rock types with poor quality. Figure 2.49 is zoomed in on two sub-segments in the central part of the field and shows facies, net/gross, porosity, and water saturation in the model. In this field the effective porosity/SW system has been modelled. The best properties are found in the lower part of the reservoir.

There is good correlation between net/gross and PHIE and the modelled PHIE are in line with the logs (Figure 2.50). Furthermore, SWE seems to be following the logs quite well.

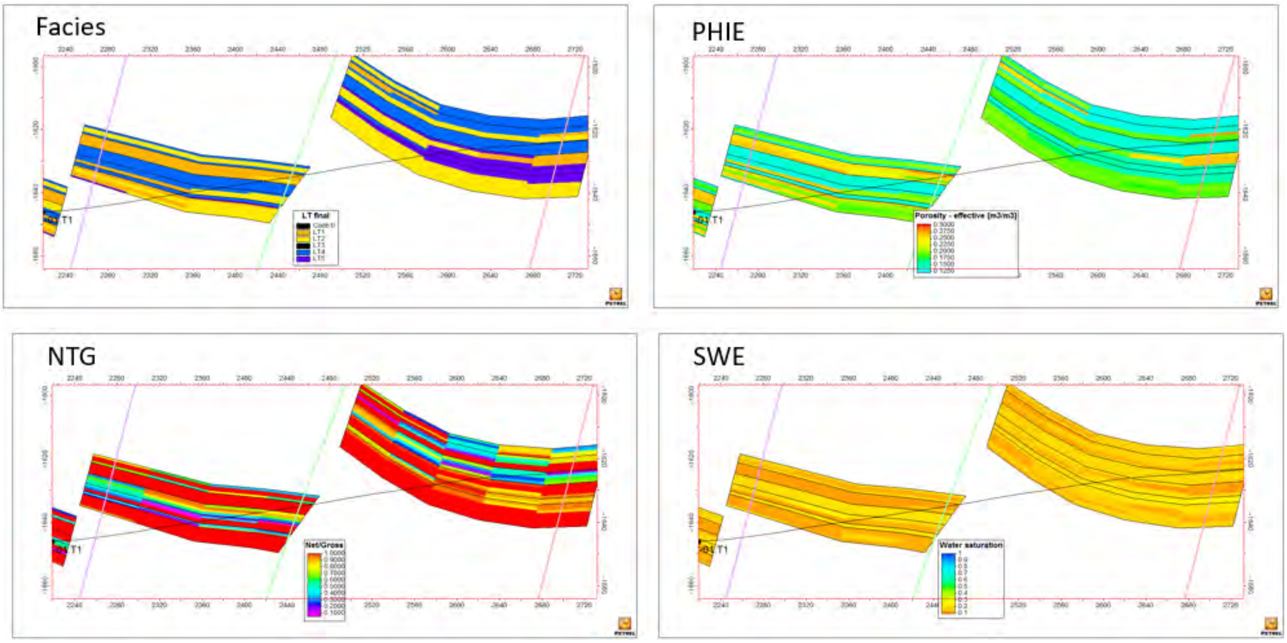


Figure 2.49 Litanzi Albian. Crossections through the static model
From Petrel project, 3D static model, Total 2009

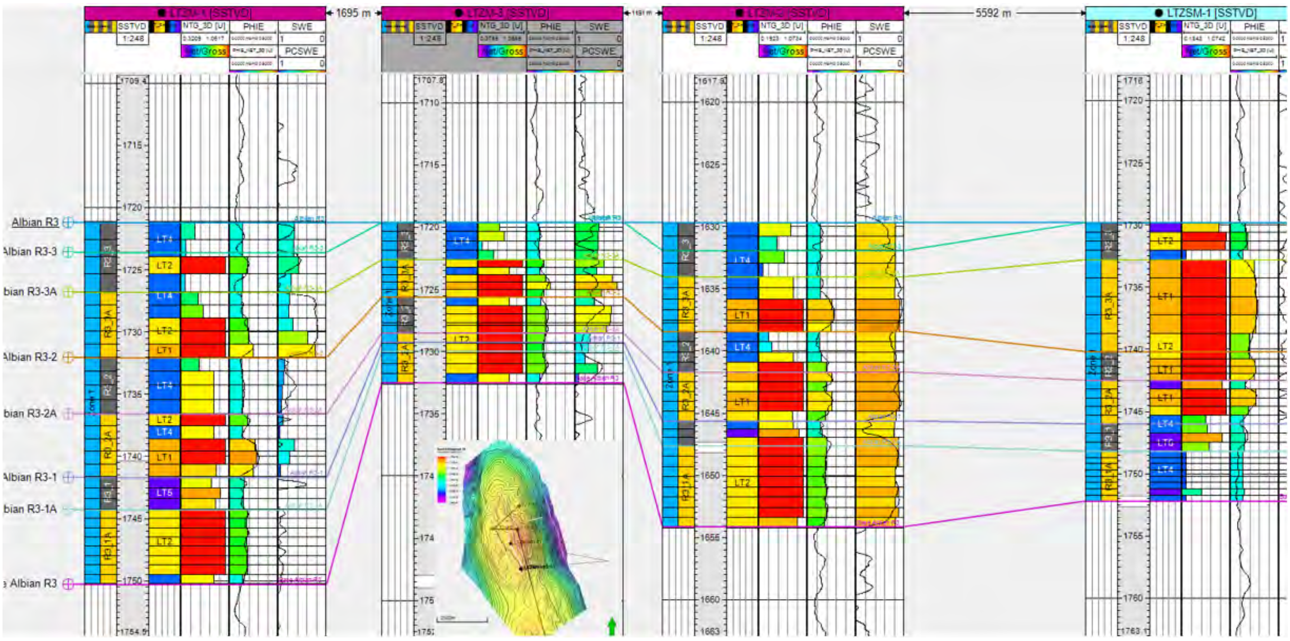


Figure 2.50 Litanzi Albian. Logs and reservoir properties
From Petrel project, 3D static model, Total 2009

STOIIP and average reservoir properties in the Albian 2009 static model is shown in Table 2.29, which is the same number as reported by Total/Perenco. The average net/gross and porosity parameters are very similar while oil saturation is slightly higher than results from the AGR petrophysical review.

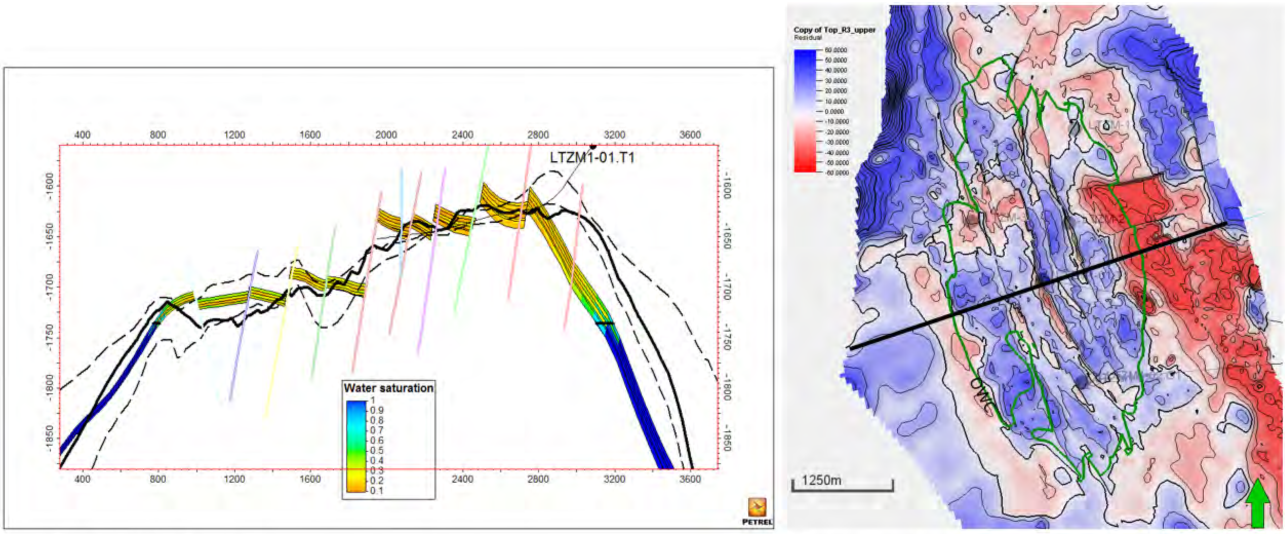
Table 2.29 Litanzi Albian STOIIP and reservoir properties in the Total 2009 static model

	Volumetrics					Average reservoir properties in the hydrocarbon zone		
Reservoir	**Gross rock volume (*10^6 m^3)**	**Net volume (*10^6 m^3)**	**Pore volume (*10^6 m^3)**	**HCPV oil (*10^6 m^3)**	**STOIIP (MMbbl)**	**net/gross**	**Porosity**	**Sw**
Albian R3-3	53.2	40.2	7.71	5.85	26.9	0.76	0.19	0.24

	Volumetrics					Average reservoir properties in the hydrocarbon zone		
Albian R3-2	47.2	40.6	7.86	5.90	27.1	0.86	0.19	0.25
Albian R3-1	23.6	22.1	4.34	3.41	15.7	0.93	0.20	0.21
Total Albian	124.0	102.9	19.92	15.17	69.6	0.83	0.19	0.24

It is AGR's view that the Total 2009 static modelling has been performed according to industry standard and with adequate quality. It is worth mentioning, however, that only one structural framework case is present and a considerable uncertainty still exists for gross rock volume.

The latest seismic surfaces from Perenco were provided to AGR. AGR compared the 2009 model with the Albian top R3 reservoir map and two high/low cases marked p90/p10 from the 2018 Perenco interpretation (Figure 2.51). The uncertainty span of the surfaces is very large. Over large parts of the Litanzi field the 2018 maps are deeper than the 2009 model. It is not possible at this stage to give a reliable estimate of the effect to the gross rock volume and STOIIP.



2009 model in background
Perenco depth surfaces in black. Base in solid, high/low with stippled lines

Difference map (depth)
Top reservoir in 2009 model compared to Perenco surface
Blue: Perenco is deeper, Red: Perenco is shallower

Figure 2.51 Litanzi. Comparison of 2009 Total model to Perenco 2018 depth surfaces

2.5.2 STOIIP/GIIP

The STOIIP for the Litanzi field is listed in Table 2.30.

The base STOIIP estimates for the Albian was presented by Perenco in the OCM meeting from June 2018. AGR can verify the base STOIIP as being in accordance with the material provided. The uncertainty span is as reported by Total in 2016 as 1P, 2P and 3P volumes. The uncertainty span has a higher upside than downside (-14%/+28%). There is no background documentation for these estimates.

Table 2.30 Litanzi in-place volumes

		STOIIP (MMbbl)		
Field	**Reservoir**	**Low**	**Base**	**High**
Tchibeli	Albian R3	59.9	69.8	89.2

2.5.3 Reservoir Engineering

Reservoir
AGR has evaluated the resource numbers and profiles in relation to the definition of the various resource classes. The main sources of data are the presentation given by Petronor and the former operator Total, and historical production data. An Eclipse model from 2010 and an older static Petrel model from 2008 exist, which is slightly modified in February 2017.

Litanzi field was discovered in 1990 and came on stream 1st of June 2006. There is only one well producing at the Litanzi field from the Albian reservoir, however, this has been a good producer with a cumulative production of 8.8 million barrels of oil. The water-cut has been increasing since breakthrough mid 2010, and is now almost 70 %, see Figure 2.52. Since mid 2016 the oil production and the water-cut has been stable. A water injector injects at a rate of 4 400 bwpd. The field has a total (accumulated) voidage of 60 %, and that is sufficient to maintain the pressure, according to Total in 2016. The water depth is 100 meter, with a reservoir depth of 1600 meter. The Albian reservoir has a porosity of 19 % and a permeability around 150 mD. The oil has a viscosity of 1 cP and a solution GOR of 124 Sm^3/Sm^3.

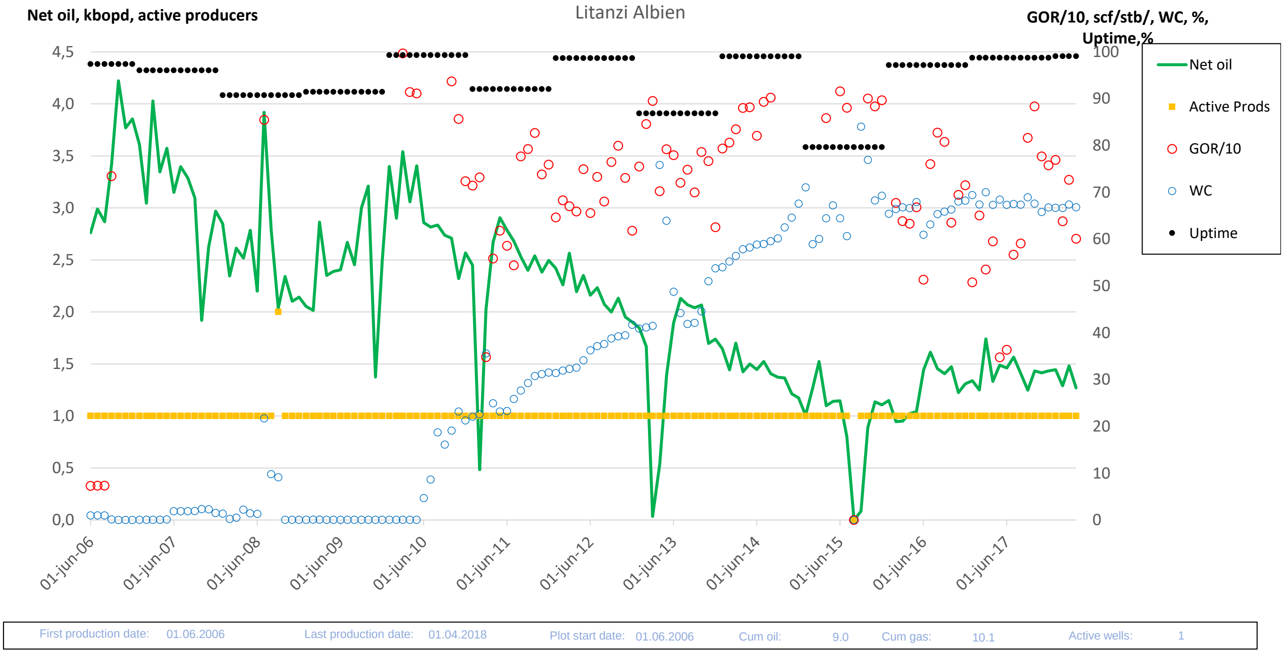


Figure 2.52 Litanzi. Historic oil production rate
The graf shows oil rate, water cut, GOR, no. of active wells and uptime

<u>Status</u>

Debottlenecking on the platform and new surface configuration (2H 2018) is expected to maintain or increase the oil production.

Production Forecasting
AGR has used the predicted oil production rates from the existing well to generate production profiles used as the basis for reserves estimation.

As for the other fields, threedifferent decline curve analysis techniques have been used on the existing wells:

1. Oil rate versus time for the entire reservoir
2. Water cut versus accumulated oil
3. Oil rate versus accumulated oil

Table 2.31 Technical oil volumes with different DCA methods

	Oil rate vs. time	Oil rate vs. cumulative oil	Water cut vs. cumulative oil
Albian reservoir	3.7	4.6	2.1

Figure 2.53 and Figure 2.54 shows two different techniques of estimating the future production base on the existing wells. Method 1) is the main technique for estimating the future production in this study, with the other methods as supportive. The low side of the rate vs. time plot corresponds to 2.3 MMbbl, roughly corresponding to the result from method 2). The result from the oil rate vs. cumulative oil roughly corresponds to the high case for method 1). Based on the information from all DCA methods and the fact that there is only one producer and one injector, the volume range is higher than the other fields; -38 % and +36 %.

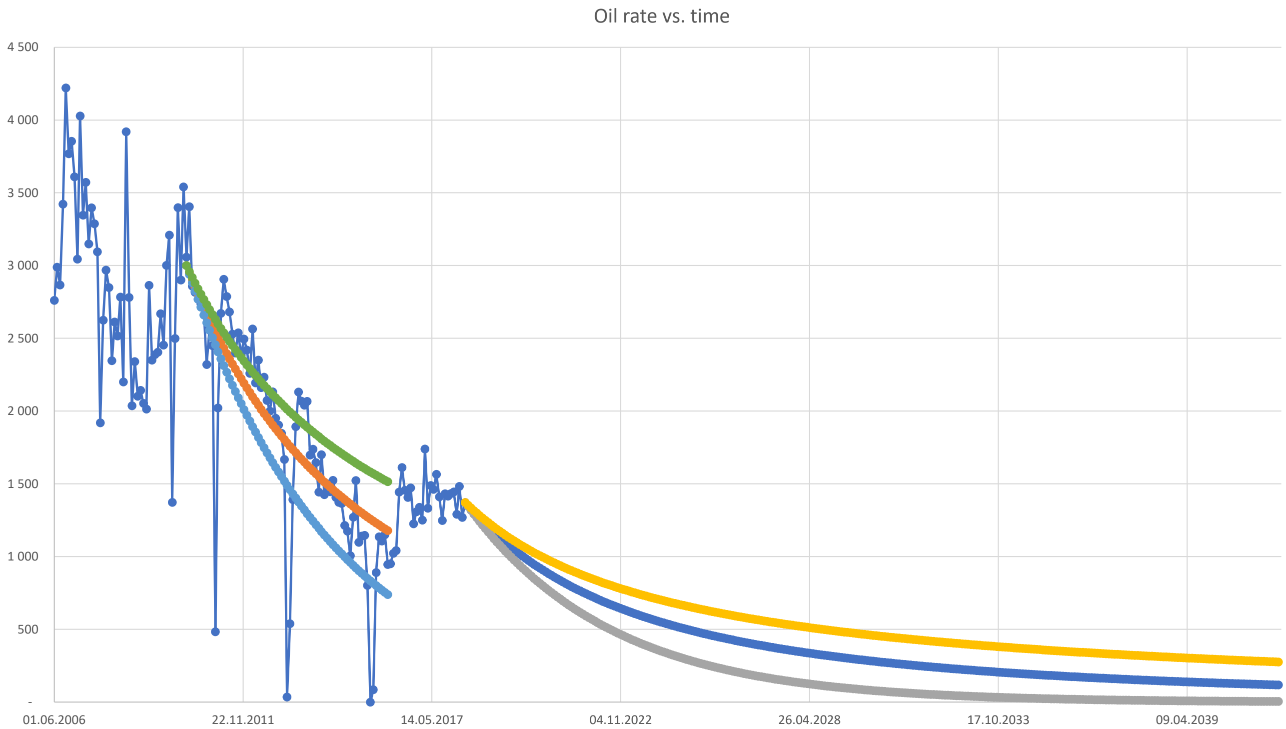


Figure 2.53 Litanzi. Decline curve analysis for future production
The base case future production is based on a b exponent of 0.5 in the hyperbolic decline formula. The orange match curve is a parallel displacement of this curve, and is meant only for illustrative purpose. Also shown are the high and low cases.

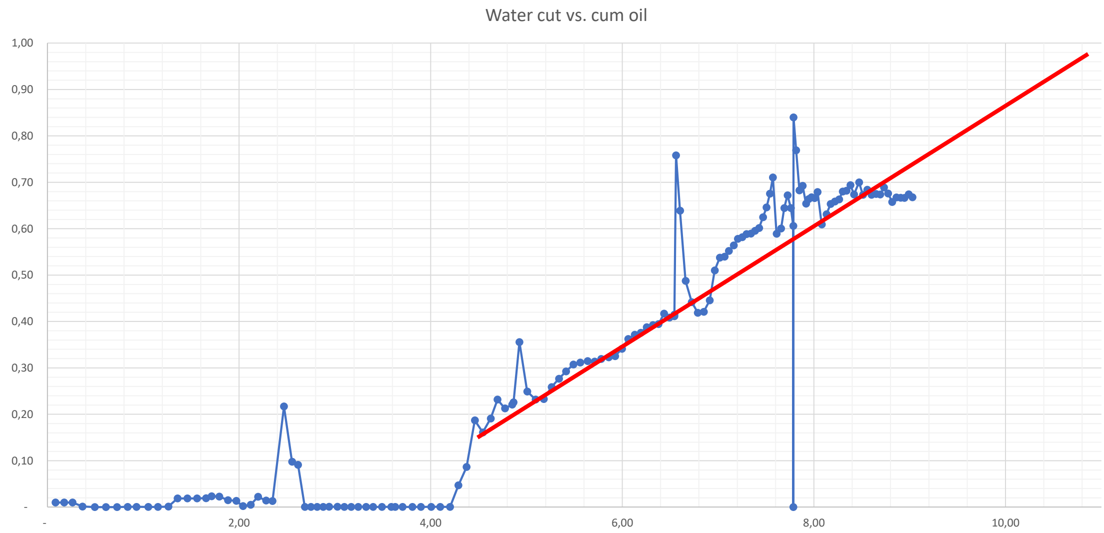


Figure 2.54 Litanzi. Water cut vs. cumulative oil
By extrapolating the water cut to 98 %, one can get an idea about the future oil volume.

Recovery Factors
The overall recovery factors for oil from the one and only producer is given in Table 2.8.

Table 2.32 Litanzi recovery factors

	Oil RF by 31.12.2017 (%)	Oil RF by 31.12.2041 (%)
Albian reservoir	13	18

Reserves and Contingent Resources Classification
The production profiles used as the basis for reserves for Litanzi are shown in Appendix A2 - Production Profiles. The underlying reserves are classified according to SPE-PRMS as follows:

- "On production": Production from existing wells.

Back in 2016 the operator Total made plans of increasing the oil volumes by 5 MMbbl in one phase, by drilling of one producer and one water injector. Since then the operatorship has been changed. Petronor, licence partner, has proposed new plans for increasing the producible volumes. A preliminary plan is as follows:

- Debottlenecking
- 1 infill well in 2020 - 2021
- 1 infill well in 2022 - 2023

The suggested plan looks feasible. However, these projects needs more studies and detailing before they can be sanctioned, and as such they are currently classified as contingent resources; "Development Unclarified". Before being booked as reserves a development plan, positive economy, a commitment from the licence and relevant approvals from the authorities, are required.

2.5.4 Recoverable Volumes

Reserves
The production profiles have been checked for economic cut-off using following assumptions, with PV Reference Date: 1.1.2018.

Table 2.33 Economic Assumptions

Economic Assumptions		
Oil Price	USD/bbl	70.0
Gas Price	USD/mscf	6

The reserves are given in the table below. The cut-off year is defined as the last year with positive cash-flow based on cost profile see A3 - Cost Profiles. For all cases, the economic cut-off year is reached at the end of 2041.

Table 2.34 Litanzi gross reserves as of 1.1.2018

Reserves, AGR review	1P	2P	3P
Oil, MMbbl	2.27	3.66	4.97
Gas, BScf	1.52	2.45	3.33
NGL, MMboe	0.00	0.00	0.00
Total, MMboe	**2.54**	**4.10**	**5.56**

Contingent Resources
The contingent resources are given in the table below.

An explanation of contingent resources is given in chapter 2.2.3 Reservoir Engineering.

Table 2.35 displays the contingent resources for Litanzi. The 2C resources include one new producer commencing production during 2020. We have no information about any estimated initial start rate for a future infill well for Litanzi. Nor have we any information if the wells will be horizontal or vertical. AGR have estimated the initial rate of the new producer to 1 200 bopd. This is less than the average of 1 350 bopd from the one and only producers in 2018. The 2C well is set with the same decline rate as the 2P profile (same b exponent, but sharper initial fall). The 3C resources adds additionally one new infill well in mid 2022. This wells is assumed with a start rate of 900 bopd. The well is set with the same deline rate (same b exponent) as the 3P profile. For the 1C resources we have assumed that the start rate of 900 bopd, and that it follow the 1P decline. The total recovery factor for the field with the estimated 2P+2C+3C volumes will be 29%, which is a reasonable high case recovery in a faulted and low permeability system. The gas resources are estimate by multiplying the oil volume by the average GOR for the two last years.

Table 2.35 Contingent Resources Litanzi (100 %) verified by AGR as of 1.1.2018 to 31.12.2041

	Oil, MMbbl			Gas, BScf			Total, MMboe		
Gross	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**	**1C**	**2C**	**3C**
Litanzi	1.4	2.6	5.0	0.9	1.8	3.4	1.5	3.0	5.6

2.5.5 Facilities Development

The Litanzi field has been developed from the Tchendo platform as seen in Figure 2.55. Production started in 2006. Oil is exported to Denjo onshore terminal.

The field platform should have significant spare capacity with the current operations and coming production trends, as seen from the historical production curves.

The below wording is copied from the Tchibuela field facilities, but is mostly relevant for Litanzi field facilities as well.

AGR observations

- AGR has not seen any Design Basis document (including design capacities and - lifetime for structures / critical equipment) and would flag lifetime as a potential concern in a twenty years aspect.
- AGR has been told that the Operator have two workover units owned by themselves and subsequently AGR do support the relative active workover strategy.
- AGR has not seen any well slot overview and status and would flag that this could be a future challenge.
- AGR does expect that Perenco has withheld Totals ordinary operation-/maintenance activities and/or any own similar programs, as AGR has not seen these.
- AGR does find the 2018 CAPEX (cathodic protection,power generation update and sealine recovery) and the 2018 OPEX (mainly well workovers/ new ESPs) to be realistic.
- AGR does support the cost figures beeing used in the economical analyses, benchmarking these with relevant inhouse cost data.
- AGR has not seen any Risk (uncertainty) Management analyses and subsequent unified "top ten" Risks Matrix from OC-and TC meetings.

AGR conclusions

- AGR concludes that there is no technical showstoppers with respect to further production in the near future, however, AGR would alarm that design lifetime (and subsequent technical integrity status) for critical steel structures and - key equipment could be an area of concern in time (especially corrosion issues).
- AGR does support Petronor's aim to follow the operators activities closely and ensure that all measures are taken, which will increase the producibility of each field.
- AGR would recommend Risk Management as an value add system, especially in implementing Petronor's upside potentials and also highlighting critical downsides as Petronor see it.

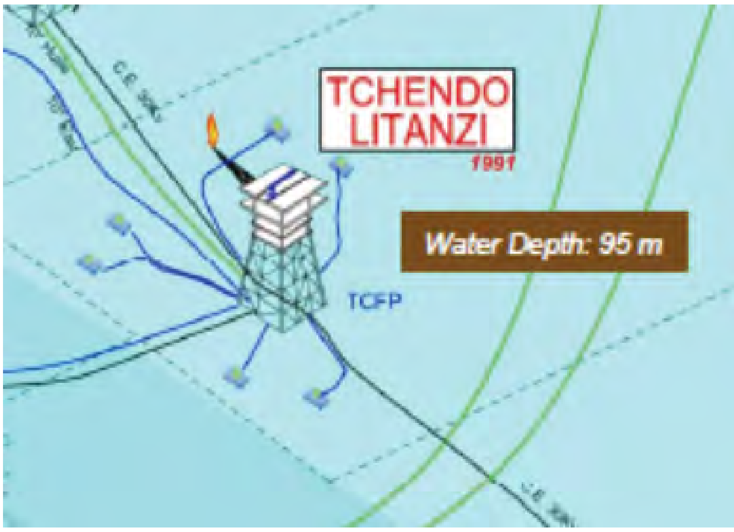


Figure 2.55 Litanzi. Facilties layout

2.6 Risks and Uncertainties

In the preceding sections a number of risks and uncertainties have been described and commented on. AGR has not seen any Risk (uncertainty) Management analyses and subsequent unified "top ten" Risks Matrix from OC- and TC meetings nor from Petronor.

AGR has the following comments/opinions to some of the key risks/uncertainties that potentially could impact production and reserves on the PNGF Sud assets:

In-place volumes

- Due to the lack of conformity of the interpretation to the eastern flank on Tchibouela Main the seismic data the STOIIP volumes may be much less. Another aspect will be the reduction in upside potential due a necessary change to the model.

- For the Tchendo field AGR observed several issues from the data room material that adds uncertainty to the STOIIP estimation and these are not fully reflected in the numbers presented by the Operator.
  - The poor quality of the seismic interpretation is poor and seismic well ties are lacking
  - The static models are outdated or were not available from former operator Total.
  - The fluid contacts and filling of the Senonian represent an uncertainty.

- Considerable uncertainty still exists for gross rock volume on Litanzi, related the relatively poor seismic data quality, thin reservoir and abundant faulting.

Recoverable Resources

- The majority of the wells are dependent on artifical lift, especially from ESPs and some from gas lift. Historically, we see that the life expectency of these pumps are from 2 - 4 years. It is therefore crucial with regulary workovers to maintain the production in all the fields.
- Several of the reservoirs are more or less dependent of water injection to keep the pressure. This is probably true for all reservoirs but Cenomanian in Tchibouela. Historically there have been problems with water injection integrity, especially exemplified from Tchendo, where 6 out of 8 injectors are closed. Water injection integrity problems pose a risk to the production.
- The distribution of the water flooded areas are uncertain. This expose future infill drilling locations to a certain risk.
- Decline analysis as method to estimate reserves in itself involves uncertainty when continuing a historical trend to prediction. Additional prediction from good simulation models would ideally have narrowed this uncertainty.

Facilities/wells

- As the platforms and subsea flowlines are ranging from more than 30 years to 10 years in operation, there could be various challenges with respect to the technical integrity status and the subsequent maintenance/operation strategy and plans. The visual inspection performed by Hemla in 2016 does encompass several activities to be undertaken to prolong platform field life. AGR has seen that Perenco has initiated some related activities, but AGR is uncertain about the present status and would advise Petronor to be "hands on" in this respect.
- Referring to Figure 2.56 AGR does notice that many of the uncertainties defined in October 2016 which relate to facilities/wells, seem to be relevant today. However, AGR has not done any thorough evaluation of these.
- AGR would recommend Risk Management as an value add system, especially in implementing Petronor's upside potentials and also highlighting critical downsides as Petronor see it.

Notes from meeting 20/10-2016

Uncertainties	Decisions
Well regularity, pump lifetime expectations	Gas generators vs. diesel for OPEX savings
Process regularity	Horizontal drilling opportunities
Possible to drill horizontal	Produce gas to LNG
	Blowdown of gas cap –> LNG
Sand production	Use gas for injection
Continue to dump produced water	Drill new wells
Establishment of operations, hand-over of operational team	Infill drilling potential
Fiscal terms	Negotiate Fiscal Terms
Oil price,	Well stimulation
Cost of Water wells and hospitals for OPEX or not and depreciation against OPEX	Additional reserves tied back to where
Deprecate investments as OPEX	Water shut-off / completion
Abandonment fund (P&A) per license, is it in existence	Increased total production capacity (process), what is current limitations ?
Political risk elements	
Price for use of oil terminals (Djeno / Nkossa)	
In-place volumes	
Recovery from the different reservoirs	
Platform integrity	
Sub-sea pipeline integrity	
Well integrity and well lifetime	
Cost of drilling of new wells	
Well intervention cost	
Availability of drilling rigs at the platforms	
OPEX, Cost reduction potential, added costs	
H2S issues	
Senonien / Tchendo producable? Fracing, Swi, STOOIP?	
Oil price scenarios	

Figure 2.56 PNGF Sud uncertainties notes 20 Oct 2016

2.7 Upsides

AGR has evaluated the possible upsides in the PNGF project based on the available information. It is AGR's opinion that possible upsides exist, as described below:

Senonian
High STOIIP and low recovery on the Tchendo field gives a room for increased recovery. A development with horizontal wells, possibly with fracking, has been proposed by Total/Perenco and Petronor.

Albian
AGR has observed that Total has built a static models over Albian, in 2006 for Tchibouela Main and in 2014 for Tchibouela East and Tchendo, indicating that there might be an upside in this reservoir. Albian Sendji Fm is the producing reservoir on Tchibeli/Litanzi.

The Top Albian has been penetrated in the first exploration well TBM01 and in a few wells on the Tchiboula fields (according to the well tops in the provided Petrel projects).

One well has penetrated the Albian reservoir on Tchendo. Perenco has listed a potential of 300 bopd for this well but the well is not active.

No further information about reservoir quality, in-place volumes nor resources for Albian on the Tchibouela and Tchendo fields has been found in the documentation provided.

Albian R2 reservoir
The Albian R2 reservoir on the Litanzi field has been penetrated and may represent an upside even if the reservoir quality is poorer than R3.

Tchibouela East
The production wells on Tchibouela East are now closed in and AGR has no information regarding any possible re-opening of the field. The low recovery factor should indicate significant upside, especially in Turonian, if the operator considers any re-development of the field. The potential for infill drilling should be considered following an update of the static/dynamic models.

Tchibeli NE
Tchibeli NE was discovered in 1989 and the reservoir level is Turonian/Cenomanian. No further information about in-place volumes nor resources has been found in the documentation provided, but the discovery may represent a future upside.

3 PNGF Bis

3.1 Asset Overview

The PNGF Bis licence, located to the northwest of PNGF Secteur Sud (Figure 3.1) is at present a licence with proven discoveries which Petronor has a right to enter into.

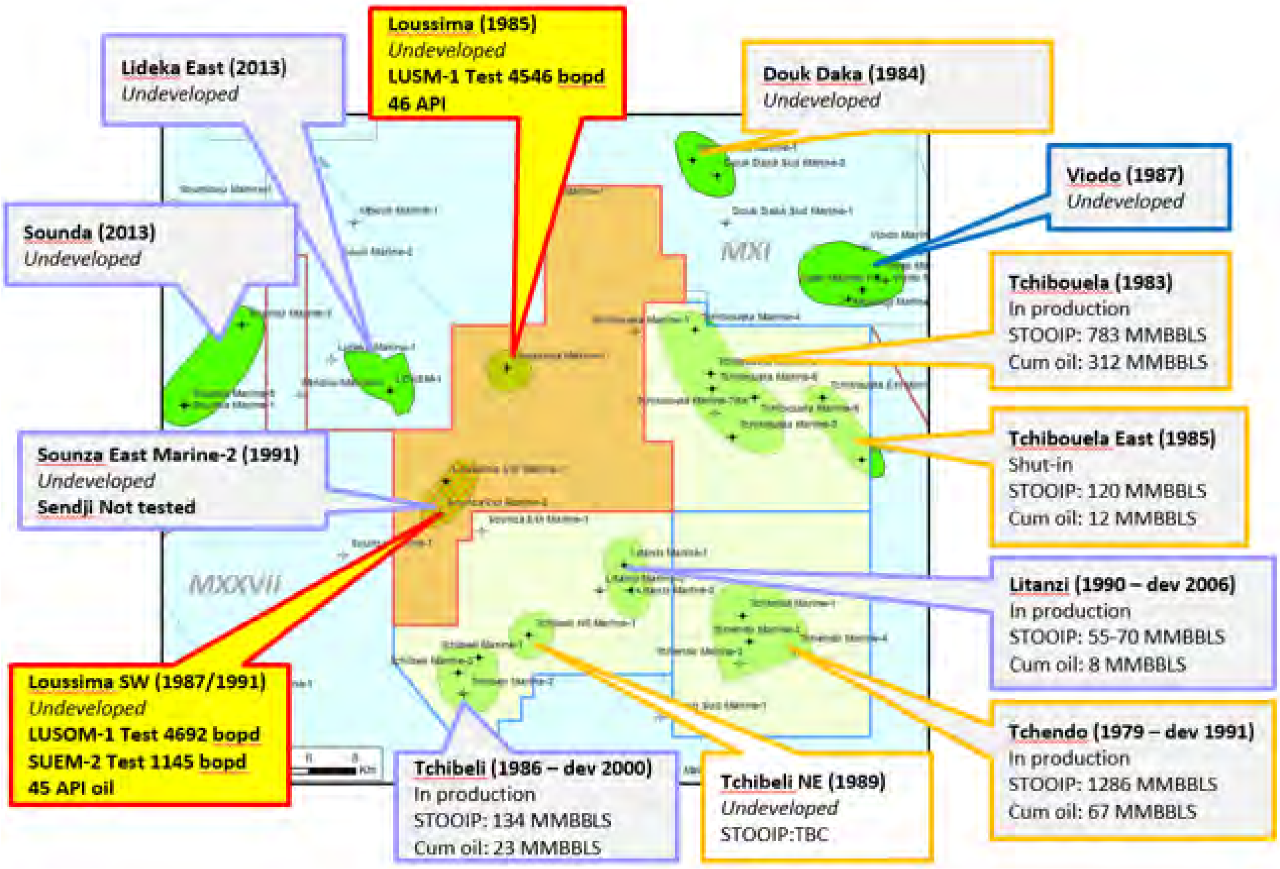


Figure 3.1 PNGF Bis licence location with surrounding producing fields and discoveries
Source: Perenco

Perenco is the current operator of the licence and took over the operatorship from the former operator Total in 2016. Contingent a decision to enter the licence, the Petronor licence interest will be 20.79%.

Table 3.1 PNGF Bis assets

Asset	Reservoir	Installation	Status	Resource category (SPE-PRMS)
Loussima SW	Vandji Fm	Well head platform	Development pending	Contingent Resources

Three exploration wells have been drilled on the licence, (Figure 3.1 and Figure 3.2). A discovery in pre-salt Vandji Fm was made in well LUSM-1 on Luossima 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 was detected in one of the wells in the Albian post-salt Sendji Fm, (analogue to Tcibeli/Litanzi reservoirs in PNGF Sud). There has not been any production yet.

The depth to the Vandji reservoir is 3250 mTVDSS, to Sendji around 1940 mTVDSS and the water depth in the area is 110 m.

Production tests on the Loussima SW in the well LUSOM-1 and in the SUEM-2 well have been promising.

Perenco has proposed a project with test/early production on Loussima SW. The project will be utilizing a used jack-up rig which will be converted and prepared for early production from one well. Tie-in to Tchibouela TAF1 through a 11 km long pipeline is planned.

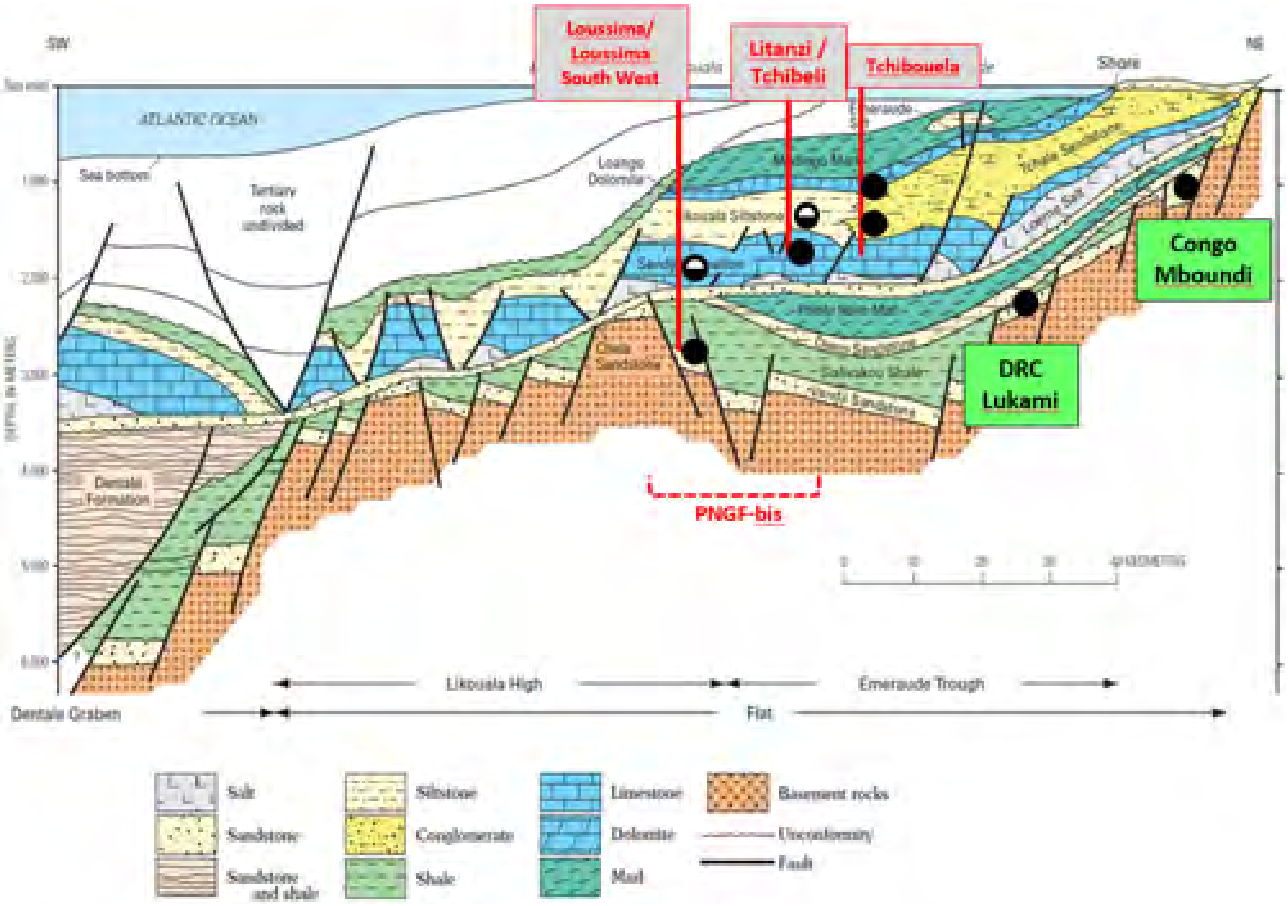


Figure 3.2 Regional geological profile with the PNGF Bis licence location
Source: Perenco

3.2 Loussima SW

3.2.1 G&G

Geological Setting
The drilled reservoir levels in PNGF Bis are both of pre-salt and post-salt age.

The Sendji Fm is similar to Albian Sendji Fm in Tchibeli/Litanzi and consists of a mix of shallow marine carbonate and clastic sediments.

The reservoir level in Vandji Fm of Neocomian age, (see Figure 2.3 for stratigraphic nomenclature), consists of a ca 500 m thick sequence with stacked sands, gravels, conglomerates and shales deposited in a fluvial/ alluvial setting. The environment ranges from alluvial fans, axial rivers, floodplain and braided river systems leading to a very heterogeneous character and low connectivity between good sands is a risk. Faults and sub-seismic faults contribute to the heterogeneity and possible intra-reservoir sealing barriers.

The structures are 4-ways or 3-ways "turtle-back" structures. Figure 3.3 shows the depth maps of the top Sendji and top Vandji reservoir levels in Loussima SW.

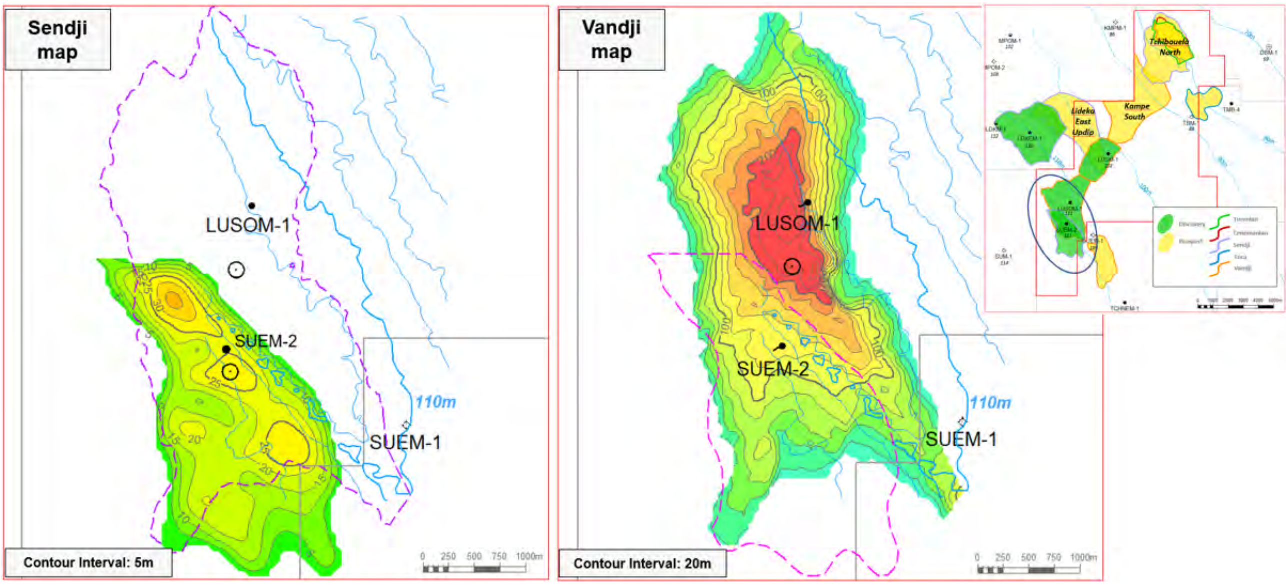


Figure 3.3 Loussima SW. Top reservoir depth maps
Left: Top Albian Sendji Fm. Right: Top pre-salt Vandji Fm. The index map shows discoveries and prospects in the licence. Source: Perenco workshop Sep 2018

Reservoir Properties
Albian Sendji Fm is penetrated within SUEM-2 and LUSOM-1 but there is hydrocarbon shows only in SUEM-2 in Lower Sendji. The 14.5 m thick zone is correlated to the reservoir level R3 in Litanzi. Reservoir properties in the SUEM-2 well are poorer than in LItanzi, as shown in Table 3.2.

Vandji Fm has been divided into seven sub-zones (Figure 3.4). The reservoir is quite heterogeneous and correlation of individual sands are difficult. Core data is available in wells SUEM-2 and LUSOM-1. Perenco has performed a study of sedimentary facies together with petrophysical evaluation of the LUSOM-1, SUEM-2 and LUSM-1 wells. Net/gross varies as do porosity and Sw. The best zones are E4 and E5 with net/gross values of 40- 50%, porosity of 11-12% and Sw of 50% in the pay zone. Permeability measured on cores are in the order of 3 to 800 mD in E4/E5.

The values in Table 3.2 are ranges in the wells as presented in documents from Perenco.

Table 3.2 Reservoir parameters in the Loussima/Loussima SW wells. From Perenco

Reservoir	Zone	Thickness		net/gross	Por	Sw (in pay zone)	Permeability (core data range)
		Gross (m)	Net (m)				mD
Sendji Fm	R3	14.5	7	0.5	0.15	0.34	0.1 - 600 mD
Vandji Fm	E1	14 - 30	0 - 4	0 - 0.10	0.09	0.35	0.1 -70 mD
	E2	10 - 19	2 - 6	0.13 - 0.25	0.09	0.42	
	E3	51 - 57	6 - 23	0.11 - 0.45	0.09	0.50	
	E4	107 - 135	52 - 55	0.40 - 0.50	0.11	0.50	3 - 800mD
	E5	88 - 122	42 - 49	0.47 - 0.52	0.12	0.54	
	E6	63 - 65	2 - 7	0.03 - 0.10	0.08	-	-
	E7	81 - 151	18 - 29	0.19 - 0.22	0.12	-	-

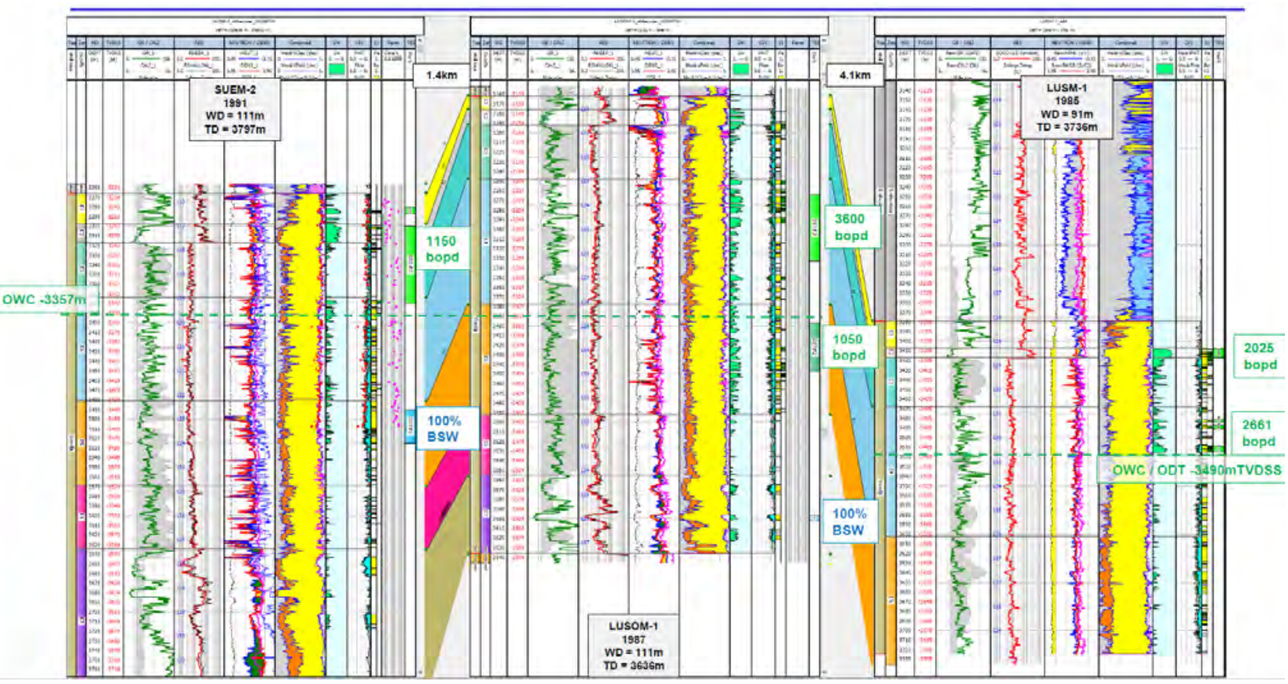


Figure 3.4 Loussima SW. Vandji Fm well correlation
Source: Perenco Workshop Sep 2018

Seismic Data

The seismic data base consists of a number of surveys which includes five 3D seismic surveys (Figure 3.5). According to the Operator: Five 3D seismic surveys were received from Congo government for PNGF Bis, four (except LUS) are cropped versions of larger surveys and no field data, partial stacks or processing reports received, though they have been requested. The Operator performed a merge of the post processed 3D's. They noted that there are CRS discrepancies between the surveys which they have corrected. Additionally the merged surveys have been phase- and time-shifted to match the MXI survey which was used as a reference. They note the best survey is the MXIV MAz which is used for the primary target. The seismic data quality is good above the Loeme Salt and poor to very poor beneath.

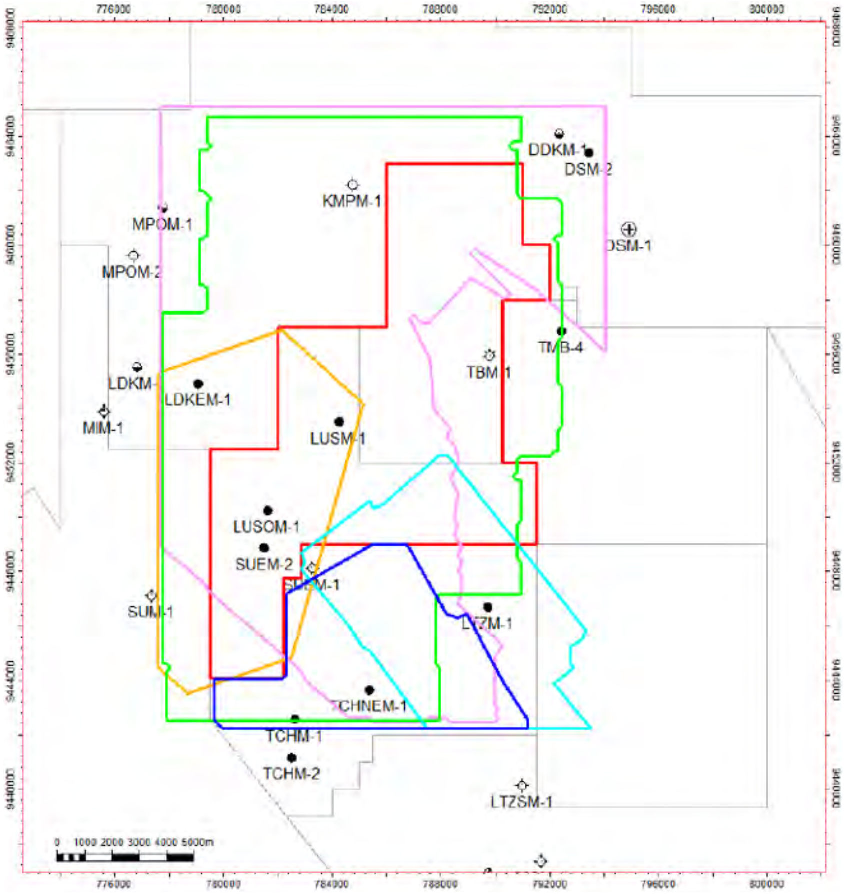


Figure 3.5 PNGF Bis 3D seismic surveys

Table 3.3 PNGF Bis Surveys

Survey	Year	Additional information	Streamer Length (km)
MXIV	2009	3 x azimuth	6
MXI	2006		5.2
LUS	1985	reprocessed 1995	1.2
Litanzi	1996		2.4
Tchibelli	1999		2.4

The operator has performed well seismic correlations which are good down to the base of the Loeme salt, but fairly poor beneath, this probably due to the poor quality of the seismic. The seismic line with well ties illustrates the challenge of correlating both between wells on the seismic as well as in the wells, (Figure 3.6).

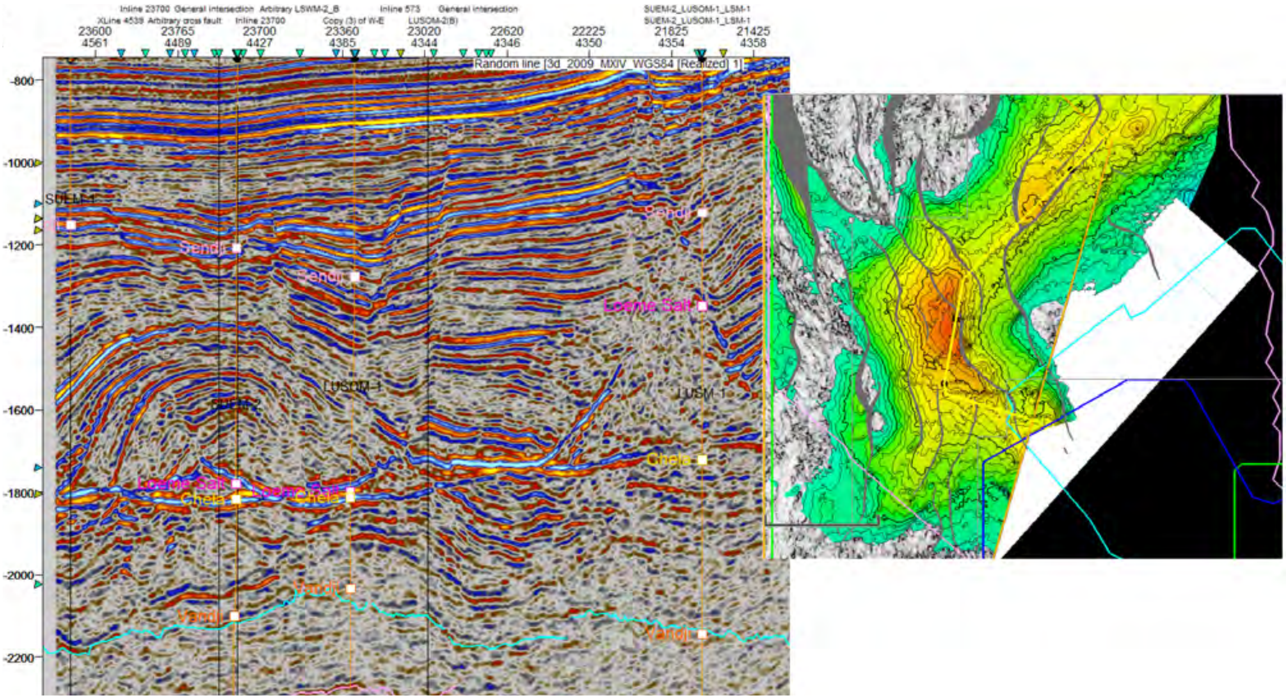


Figure 3.6 Well seismic correlation across the PNGF Bis licence

The seismic interpretation for the Vandji and basement are reasonable for the quality of the seismic data (). It helps that there are three wells that penetrate these horizons for control. Due to the quality of the seismic there may be more faults than have been interpreted. It should be noted that there is deeper oil contact in LUSOM-1 than in Suem-2. This may indicate an additional fault in between these two wells. The approach applied for depth conversion and correction to the wells due to mis-ties is Standard Industry Practice.

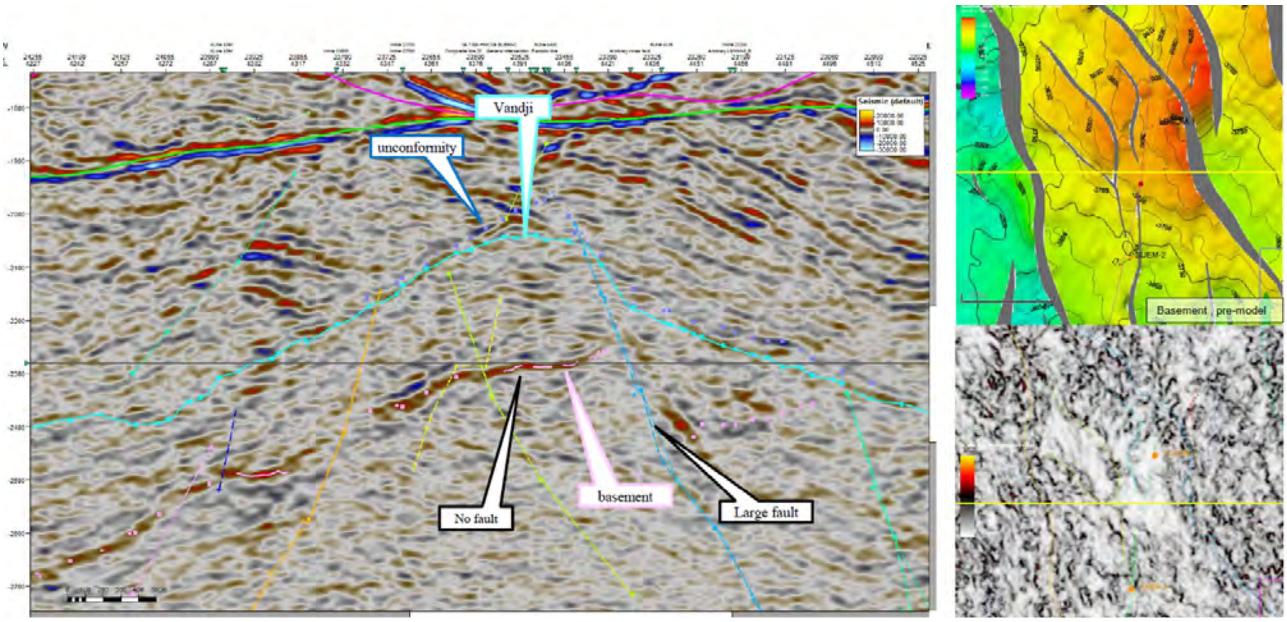


Figure 3.7 Loussoma SW. Seismic interpretation Vandji and Basement.

Reservoir pressure and fluid contacts

Reservoir pressure gradients show many pressure regimes on a detailed scale and there are definitely not completely communication between Vandji Fm reservoir sub-zones and between wells. One OWC is interpreted at 3357 mTVDSS in well SUEM-2 in E4. Top reservoir map has a closure at this depth. Else oil-down-to and water-up to situations have been logged. Production tests with rates are marked in Figure 3.4 and it is obvious that the 3357 mTVDSS is not a common OWC for all sub-zones. A deeper OWC in E5, at 3412 mTVDSS has been introduced as an upside case.

3.2.2 STOIIP/GIIP

In-place volumes for Loussima SW is based on the subsurface studies presented by Perenco to the licence in a workshop in September 2018.

Figure 3.8 shows the input for an oil-down-to case of the Sendji R3 reservoir level, for the whole field and an eastern fault segment. This case is to be regarded as a high case and it should also be noted that the volumes are not proven. There is only hydrocarbon shows in SUEM-2, no moveable oil has been proven. Further, reservoir property input, net/gross, porosity and hydrocarbon saturation, is more optimistic than interpreted in SUEM-2.

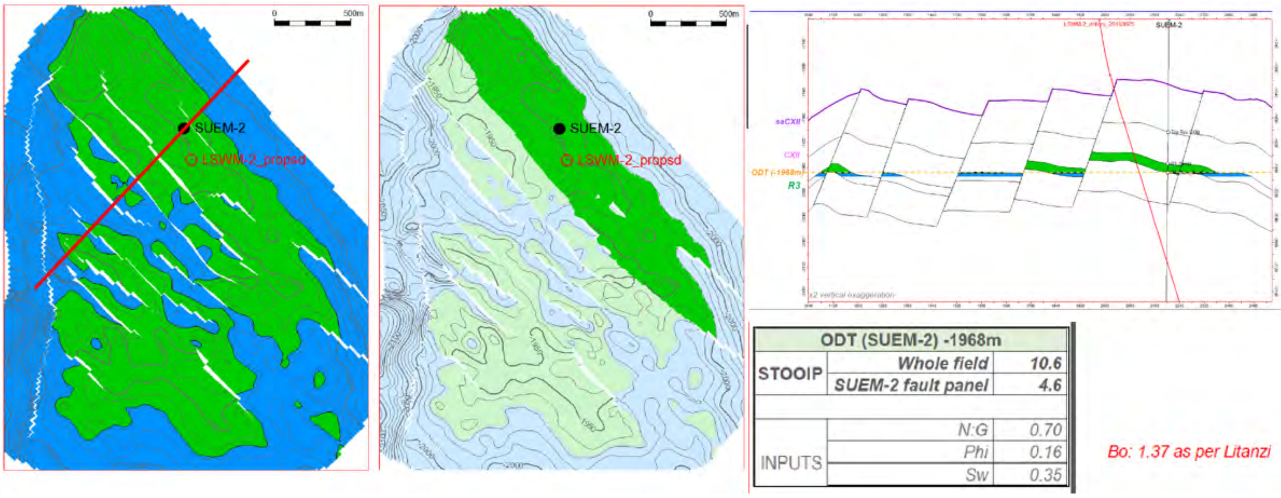
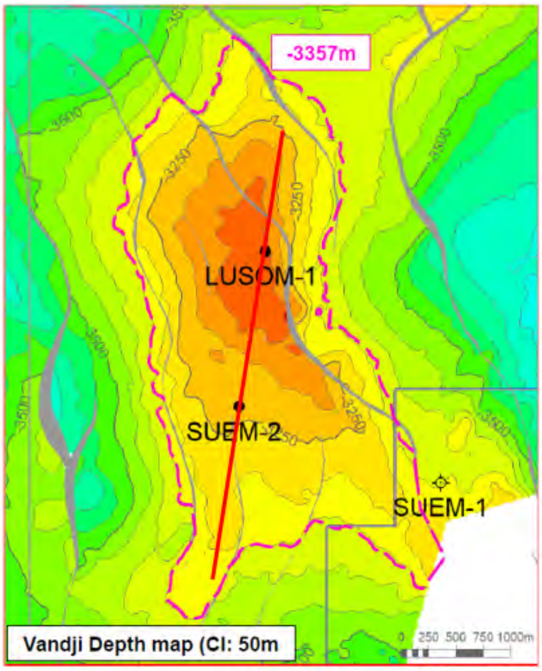
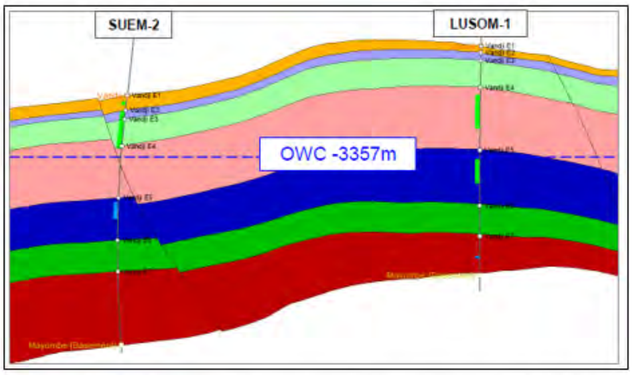


Figure 3.8 Loussima SW Albian. STOIIP estimation for Sendji R3 Fm
Source: Perenco

The volume estimations for Vandji Fm is illustrated in Figure 3.9. An additional case with deeper filling in E5 gives an extra 10 MMbbl of STOIIP. The reservoir properties are taken from the petrophysics in the wells and are reasonable for a base case. The main risks are related to connectivity between the sands, fluid contacts and gross rock volume.





Zone	GRV (1E6m3)	NTG	Phi	So	Bo	STOOIP (mmstb)
E1	243	0.10	0.09	0.65	1.42	6
E2	143	0.20	0.09	0.65	1.42	7
E3	341	0.30	0.11	0.65	1.42	32
E4	268	0.50	0.11	0.65	1.42	42
E5	7	0.50	0.12	0.65	1.42	1
E6	-	-	-	-	-	-
E7	-	-	-	-	-	-
					TOTAL	90

Figure 3.9 Loussima SW Pre-salt. STOIIP estimation or Vandji Fm

No static uncertainty analysis has been documented in the data room.

Table 3.4 Litanzi in-place volumes

		STOIIP (MMbbl)		
Field	**Reservoir**	**Low**	**Base**	**High**
Loussima SW	Vandji	-	90	-

3.2.3 Reservoir Engineering

Two DSTs have been performed in Loussima SW; one in well LUSOM-1 and one in well SUEM-2, see Figure 3.9. Both wells found similar oil characteristics. The oil is light (41 deg. API) with paraffins. Estimated oil viscosity is 0.5 cP, solution GOR of 700 scf/stb and a FVF of 1.4. Saturation pressure is approx. 3 300 psi, which is below the initial pressure of approx. 5 300 psi in both wells.

LUSOM-1

The DST revealed a PI between 1.2 and 2.0 bopd/psi, with a maximum flowing oil rate of 3 600 bopd in a 10 m interval. A quick and simple test was done by AGR in MBAL to estimate the permeability in this test. The tested interval has a NTG of 0.5 and a porosity of 0.11, this means effective test interval of 5 m. Relevant PVT and PI was input to the model. The estimation gave a permeability of 100 mD to match the maximum given PI of 2.0 bopd/psi. The permeability should therefore probably be equal to or below 100 mD. Porosity-permeability relationship of core data from both wells indicates permeabilities around 10 - 20 mD with an average porosity of 0.11, lower than estimated with MBAL.

SUEM-2

The DST revealed a PI between 0.25 and 0.5 bopd/psi, with a maximum flowing oil rate of 1 145 bopd in a 80 m interval. The porosity in this interval varies between 0.09 - 0.11, indicating permeabilities from phi-K relationship to approx. 10 mD.

Planned long term test

Plans exist for a long term test with one well in Vandji Fm., with a possibility for also producing from the shallower Senji Fm. (not proven and no DST). The well will be connected to the infrastructure on PNGS Sud, and probably be converted to a permanent producer after the test is terminated. A study has already started and estimated start-up is set to Q2 2019.

Both DSTs in LUSOM-1 and SUEM-2 wells show good initial oil flows during the DST. However, depletion from RFT indicates risk of limited volumes connected to the wells (mentioned in final well report). On the other hand, log correlations, pressure gradients and oil quality indicate good chance of connectivity despite the likelihood of baffles. Analogue fields indicates reserves of 5 MMstb per well.

A technical workshop from September 2018 on Bis indicates an oil volume of 1.9 MMbbl for this test well after 7 years of production, with a decline rate the first year of 55 % and 15 % annually after that.

AGR comment

On the positive side the oil viscosity is low, contrarly the permeability in central part of Loussima SW is mediocre. It is even lower towards well SUEM-2. However, the DST showed oil rates of 3 600 bopd from a 10 m interval. We have no information about the planned well, if it is vertical or horizontal, nor about the completion length. Nevertheless, AGR believe that an estimated start rate of 2 500 bopd is conservative, especially if the test well is completed as a horizontal well with completion lengths of several hundreds meters. If the MBAL calculated permeability is correct, and this permeability is extensive around the well, it should be feasible producing this rate and keep the decline rate less than 55 % the first year. The operator estimated oil volume of 1.9 MMbbl after 7 years, is thus probably on the low side.

3.2.4 Recoverable Volumes

Reserves
As far as we know, no firm commitment have been undertaken by the stakeholder and the relevant approvals from the authorities has not been granted. The planned long term test well does thus not satisfy the conditions to be booked as reserves.

Contingent Resources
The contingent resources, classified as "Development Pending", in Table 3.5 is estimated by the operator for the Vandji Fm, and is based on the volume to pay back the investment. There exists plans to also recover oil from the shallower Sendji Fm (STOIIP = 10 MMbbl). These volumes are not stated in this report as the in-place volumes are not proven. AGR endorse the volumes, but believe on the same time that they are conservative.

Table 3.5 Contingent Resources Long term test well (100 %) verified by AGR. Resources classified as "Development pending". Values given by the operator for Vandji Fm.

	Oil, MMbbl		
Gross	**1C**	**2C**	**3C**
Test well. 7 years production, as given by Perenco	0.4	1.9	3.8

A full field development is foreseen based on a positive outcome of the planned long term test. Based on experience from analogue fields the development could include 5 - 7 long horizontal producers combined with water injectors. Based on the limited knowledge of the geology and the PVT, AGR would consider a plausible recovery factor to be from 25 - 35 % for such a field. This amounts to 22 - 32 MMbbl with an estimated STOIIP of 90 MMbbl, see Table 3.6. These contingent resources are classified as "Development Unclarified".

Table 3.6 Contingent resources Full field development of Loussima SW. Classified as "Development Unclearified".

	Oil, MMbbl		
Gross	**1C**	**2C**	**3C**
Full field development	22	27	32

3.2.5 Facilities Development

AGR has briefly reviewed Perenco's /Petronor's future field facilities development in the sense of the risks and value aspects. AGR does support Perenco's/Petronor's way of thinking/strategy for development i.e. stepwise development starting with a combined "test production -/production" well tied in to a low cost rented platform. The development is planned to be facilitated by an old jack-up with some necessary topside upgrading and a subsea flowline tied back to the PNGF Sud infrastructure, as seen in figure Figure 3.10.

The future development is pending the experienced results.

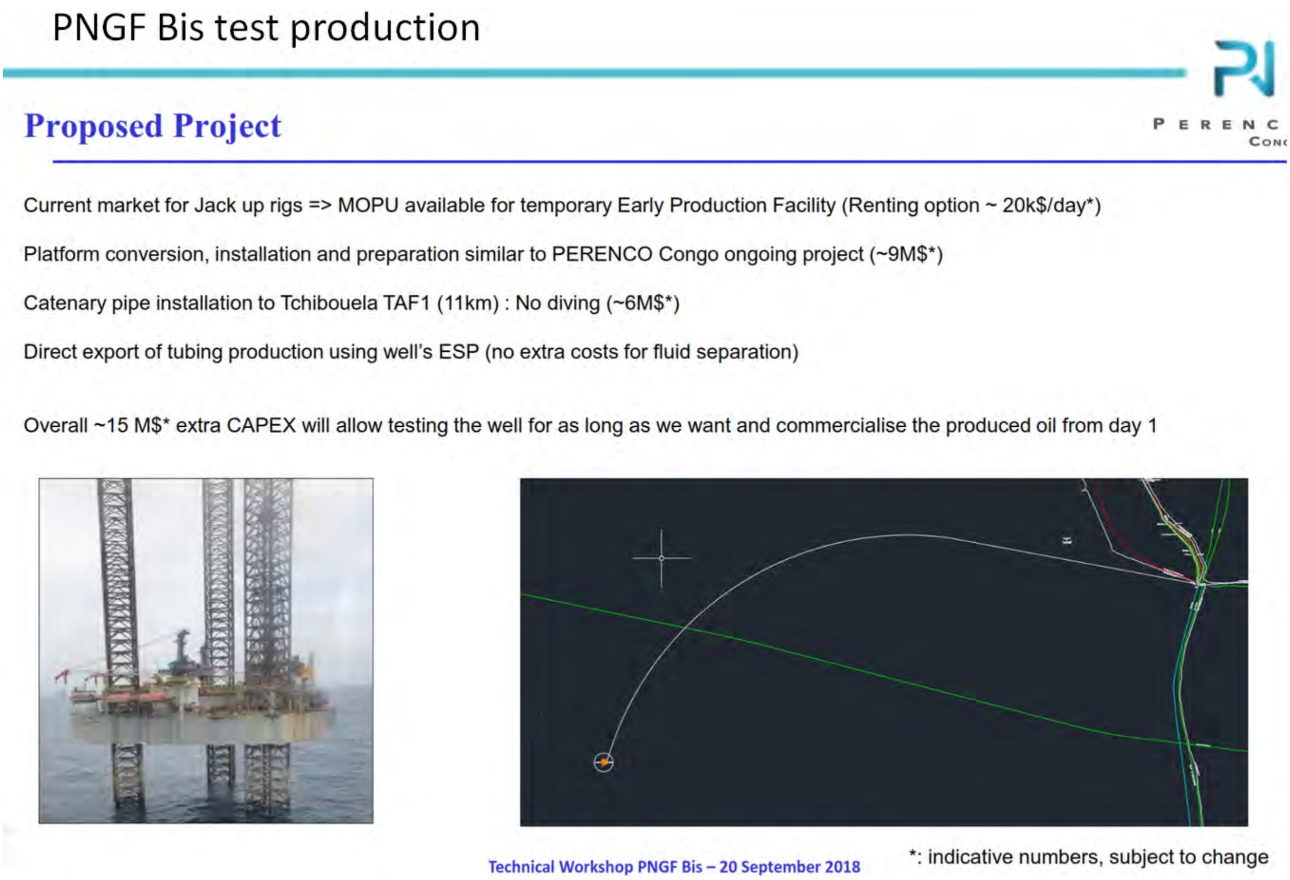


Figure 3.10 PNGF Bis facilities project

3.2.6 Risks and Uncertainty

In-place volumes
The uncertainty with Bis is the interpretation of Vandji and Sendji. There is probaly a lower uncertainty with the Sendji interpretation due to the quality of the seismic is better than for Vandji.

Recoverable resources
The permeability of the field is uncertain, even with the data from the two DSTs, as the range in Productivity Index is high between the wells.

3.2.7 Upsides

The upside in PNGF Bis is related to an upside in the in-place volumes and the possibility of tying in additional wells in Loussma SW. The first planned well will test productivity and is expected to give valuable information about future potential.

There is also a discovery in the Loussima well LUSM-1. This well proved light oil (46 deg API) with low viscosity (mu=0.25 cP) and GOR=2700 scf/stb. The DST revealed productivity index of 2.6 - 4.3 bopd/psi due to very favorable mobility ratio. A development of this field will be a significant upside to the existing resources in the PNGF Bis license. We have seen no estimation of the STOIIP in Loussima.

4 Key References

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- PNGF Technical reports
- Economical evaluation models

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Litanzi

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Appendix

A1 - Summary of 2018 SPE Petroleum Resources Classification

The following table has paragraphs that are quoted from the 2007 SPE PRMS Guidance Notes and summarise the key resources categories, while Figure 1shows the recommended resources classification framework.

Table 1 Summary of 2007 SPE Petroleum Resources Classification

Class/Sub-class	Definition
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.
On Production	The development project is currently producing and selling petroleum to market.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development on Hold	A discovered accumulation where project activities are on hold and/ or where justification as a commercial development may be subject to significant delay.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.

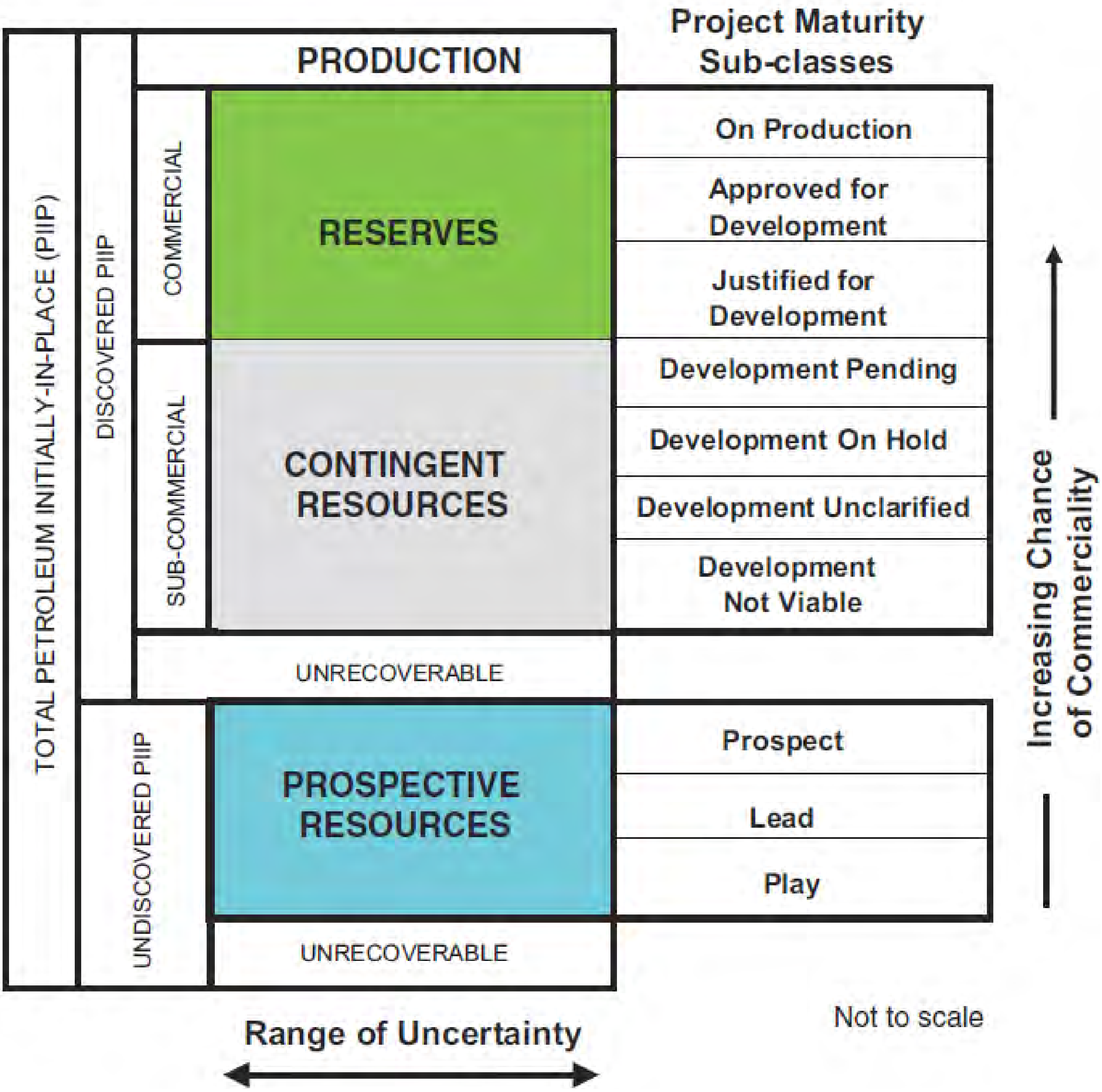

Figure 1 Illustration of the SPE's reserves classification system, PRMS

A2 - Production Profiles

All production profiles are 100 % share profiles.

Tchibouela

Table 2 Tchibouela, Technical Production Profile P90. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	12382	5052	0	4.52	1.84	0.00	4.85
2019	365	11201	4570	0	4.09	1.67	0.00	4.39
2020	366	10027	4091	0	3.67	1.50	0.00	3.94
2021	365	9025	3682	0	3.29	1.34	0.00	3.53
2022	365	8101	3305	0	2.96	1.21	0.00	3.17
2023	365	7272	2967	0	2.65	1.08	0.00	2.85
2024	366	6510	2656	0	2.38	0.97	0.00	2.56
2025	365	5859	2391	0	2.14	0.87	0.00	2.29
2026	365	5259	2146	0	1.92	0.78	0.00	2.06
2027	365	4721	1926	0	1.72	0.70	0.00	1.85
2028	366	4226	1724	0	1.55	0.63	0.00	1.66
2029	365	3804	1552	0	1.39	0.57	0.00	1.49
2030	365	3414	1393	0	1.25	0.51	0.00	1.34
2031	365	3065	1250	0	1.12	0.46	0.00	1.20
2032	366	2744	1119	0	1.00	0.41	0.00	1.08
2033	365	2470	1008	0	0.90	0.37	0.00	0.97
2034	365	2217	904	0	0.81	0.33	0.00	0.87
2035	365	1990	812	0	0.73	0.30	0.00	0.78
2036	366	1781	727	0	0.65	0.27	0.00	0.70
2037	365	1603	654	0	0.59	0.24	0.00	0.63
2038	365	1439	587	0	0.53	0.21	0.00	0.56
2039	365	1292	527	0	0.47	0.19	0.00	0.51
2040	366	1156	472	0	0.42	0.17	0.00	0.45
2041	365	1041	425	0	0.38	0.16	0.00	0.41
Total					**41.13**	**16.78**	**0.00**	**44.11**

Table 3 Tchibouela, Technical Production Profile P50. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	12388	5054	0	4.52	1.84	0.00	4.85
2019	365	11265	4596	0	4.11	1.68	0.00	4.41
2020	366	10208	4165	0	3.74	1.52	0.00	4.01
2021	365	9357	3818	0	3.42	1.39	0.00	3.66
2022	365	8599	3508	0	3.14	1.28	0.00	3.37
2023	365	7940	3239	0	2.90	1.18	0.00	3.11
2024	366	7342	2995	0	2.69	1.10	0.00	2.88
2025	365	6852	2796	0	2.50	1.02	0.00	2.68
2026	365	6400	2611	0	2.34	0.95	0.00	2.51
2027	365	5996	2446	0	2.19	0.89	0.00	2.35
2028	366	5618	2292	0	2.06	0.84	0.00	2.21
2029	365	5307	2165	0	1.94	0.79	0.00	2.08

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
2030	365	5011	2045	0	1.83	0.75	0.00	1.96
2031	365	4742	1935	0	1.73	0.71	0.00	1.86
2032	366	4485	1830	0	1.64	0.67	0.00	1.76
2033	365	4273	1743	0	1.56	0.64	0.00	1.67
2034	365	4067	1659	0	1.48	0.61	0.00	1.59
2035	365	3877	1582	0	1.42	0.58	0.00	1.52
2036	366	3692	1506	0	1.35	0.55	0.00	1.45
2037	365	3540	1444	0	1.29	0.53	0.00	1.39
2038	365	3390	1383	0	1.24	0.50	0.00	1.33
2039	365	3250	1326	0	1.19	0.48	0.00	1.27
2040	366	3111	1269	0	1.14	0.46	0.00	1.22
2041	365	2998	1223	0	1.09	0.45	0.00	1.17
Total					**52.49**	**21.42**	**0.00**	**56.30**

Table 4 Tchibouela, Technical Production Profile P10. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	12451	5080	0	4.54	1.85	0.00	4.87
2019	365	11599	4732	0	4.23	1.73	0.00	4.54
2020	366	10772	4395	0	3.94	1.61	0.00	4.23
2021	365	10107	4124	0	3.69	1.51	0.00	3.96
2022	365	9496	3875	0	3.47	1.41	0.00	3.72
2023	365	8955	3654	0	3.27	1.33	0.00	3.51
2024	366	8450	3447	0	3.09	1.26	0.00	3.32
2025	365	8039	3280	0	2.93	1.20	0.00	3.15
2026	365	7648	3121	0	2.79	1.14	0.00	2.99
2027	365	7293	2976	0	2.66	1.09	0.00	2.86
2028	366	6951	2836	0	2.54	1.04	0.00	2.73
2029	365	6674	2723	0	2.44	0.99	0.00	2.61
2030	365	6402	2612	0	2.34	0.95	0.00	2.51
2031	365	6152	2510	0	2.25	0.92	0.00	2.41
2032	366	5904	2409	0	2.16	0.88	0.00	2.32
2033	365	5705	2328	0	2.08	0.85	0.00	2.23
2034	365	5506	2246	0	2.01	0.82	0.00	2.16
2035	365	5319	2170	0	1.94	0.79	0.00	2.08
2036	366	5131	2094	0	1.88	0.77	0.00	2.01
2037	365	4982	2033	0	1.82	0.74	0.00	1.95
2038	365	4829	1970	0	1.76	0.72	0.00	1.89
2039	365	4685	1912	0	1.71	0.70	0.00	1.83
2040	366	4537	1851	0	1.66	0.68	0.00	1.78
2041	365	4422	1804	0	1.61	0.66	0.00	1.73
Total					**62.83**	**25.63**	**0.00**	**67.39**

Table 5 Tchibouela, Technical Production Profile C2 resources. Production commencing July 2020.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	0	0	0	0	0	0	0
2019	365	0	0	0	0	0	0	0

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
2020	365/2	1935	789570	0	0.35	0.14	0	0.38
2021	365	2704	1103061	0	0.99	0.40	0	1.06
2022	365	3229	1317564	0	1.18	0.48	0	1.26
2023	365	2809	1146137	0	1.03	0.42	0	1.10
2024	366	2474	1009473	0	0.90	0.37	0	0.97
2025	365	2202	898385	0	0.80	0.33	0	0.86
2026	365	1977	806598	0	0.72	0.29	0	0.77
2027	365	1788	729691	0	0.65	0.27	0	0.70
2028	366	1629	664473	0	0.59	0.24	0	0.64
2029	365	1492	608582	0	0.54	0.22	0	0.58
2030	365	1373	560240	0	0.50	0.20	0	0.54
2031	365	1270	518083	0	0.46	0.19	0	0.50
2032	366	1179	481049	0	0.43	0.18	0	0.46
2033	365	1099	448302	0	0.40	0.16	0	0.43
2034	365	1027	419172	0	0.37	0.15	0	0.40
2035	365	964	393121	0	0.35	0.14	0	0.38
2036	366	906	369707	0	0.33	0.13	0	0.35
2037	365	854	348569	0	0.31	0.13	0	0.33
2038	365	807	329407	0	0.29	0.12	0	0.32
2039	365	765	311969	0	0.28	0.11	0	0.30
2040	366	726	296045	0	0.26	0.11	0	0.28
2041	365	690	281455	0	0.25	0.10	0	0.27
Total					**12.00**	**4.90**	**0.00**	**12.89**

Tchendo

Table 6 Tchendo, Technical Production Profile P90. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	4688	1641	0	1.71	0.60	0.00	1.82
2019	365	4089	1431	0	1.49	0.52	0.00	1.59
2020	366	3406	1192	0	1.25	0.44	0.00	1.32
2021	365	2853	998	0	1.04	0.36	0.00	1.11
2022	365	2383	834	0	0.87	0.30	0.00	0.92
2023	365	1990	697	0	0.73	0.25	0.00	0.77
2024	366	1658	580	0	0.61	0.21	0.00	0.64
2025	365	1389	486	0	0.51	0.18	0.00	0.54
2026	365	1160	406	0	0.42	0.15	0.00	0.45
2027	365	969	339	0	0.35	0.12	0.00	0.38
2028	366	807	282	0	0.30	0.10	0.00	0.31
2029	365	676	237	0	0.25	0.09	0.00	0.26
2030	365	565	198	0	0.21	0.07	0.00	0.22
2031	365	472	165	0	0.17	0.06	0.00	0.18
2032	366	393	137	0	0.14	0.05	0.00	0.15
2033	365	329	115	0	0.12	0.04	0.00	0.13
2034	365	275	96	0	0.10	0.04	0.00	0.11
2035	365	230	80	0	0.08	0.03	0.00	0.09
2036	366	191	67	0	0.07	0.02	0.00	0.07
2037	365	160	56	0	0.06	0.02	0.00	0.06

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
2038	365	134	47	0	0.05	0.02	0.00	0.05
2039	365	112	39	0	0.04	0.01	0.00	0.04
2040	366	93	33	0	0.03	0.01	0.00	0.04
2041	365	78	27	0	0.03	0.01	0.00	0.03
Total					**10.63**	**3.72**	**0.00**	**11.29**

Table 7 Tchendo, Technical Production Profile P50. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	4766	1668	0	1.74	0.61	0.00	1.85
2019	365	4503	1576	0	1.64	0.58	0.00	1.75
2020	366	4108	1438	0	1.50	0.53	0.00	1.60
2021	365	3782	1324	0	1.38	0.48	0.00	1.47
2022	365	3485	1220	0	1.27	0.45	0.00	1.35
2023	365	3222	1128	0	1.18	0.41	0.00	1.25
2024	366	2979	1043	0	1.09	0.38	0.00	1.16
2025	365	2777	972	0	1.01	0.35	0.00	1.08
2026	365	2589	906	0	0.94	0.33	0.00	1.00
2027	365	2419	847	0	0.88	0.31	0.00	0.94
2028	366	2259	791	0	0.83	0.29	0.00	0.88
2029	365	2125	744	0	0.78	0.27	0.00	0.82
2030	365	1998	699	0	0.73	0.26	0.00	0.77
2031	365	1882	659	0	0.69	0.24	0.00	0.73
2032	366	1771	620	0	0.65	0.23	0.00	0.69
2033	365	1679	588	0	0.61	0.21	0.00	0.65
2034	365	1589	556	0	0.58	0.20	0.00	0.62
2035	365	1506	527	0	0.55	0.19	0.00	0.58
2036	366	1426	499	0	0.52	0.18	0.00	0.55
2037	365	1359	476	0	0.50	0.17	0.00	0.53
2038	365	1294	453	0	0.47	0.17	0.00	0.50
2039	365	1233	431	0	0.45	0.16	0.00	0.48
2040	366	1173	411	0	0.43	0.15	0.00	0.46
2041	365	1123	393	0	0.41	0.14	0.00	0.44
Total					**20.84**	**7.29**	**0.00**	**22.14**

Table 8 Tchendo, Technical Production Profile P10. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	4783	1674	0	1.75	0.61	0.00	1.85
2019	365	4599	1610	0	1.68	0.59	0.00	1.78
2020	366	4279	1498	0	1.57	0.55	0.00	1.66
2021	365	4021	1407	0	1.47	0.51	0.00	1.56
2022	365	3784	1324	0	1.38	0.48	0.00	1.47
2023	365	3573	1251	0	1.30	0.46	0.00	1.39
2024	366	3375	1181	0	1.24	0.43	0.00	1.31
2025	365	3215	1125	0	1.17	0.41	0.00	1.25
2026	365	3061	1071	0	1.12	0.39	0.00	1.19
2027	365	2921	1023	0	1.07	0.37	0.00	1.13

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
2028	366	2786	975	0	1.02	0.36	0.00	1.08
2029	365	2677	937	0	0.98	0.34	0.00	1.04
2030	365	2570	900	0	0.94	0.33	0.00	1.00
2031	365	2471	865	0	0.90	0.32	0.00	0.96
2032	366	2373	830	0	0.87	0.30	0.00	0.92
2033	365	2294	803	0	0.84	0.29	0.00	0.89
2034	365	2215	775	0	0.81	0.28	0.00	0.86
2035	365	2141	749	0	0.78	0.27	0.00	0.83
2036	366	2066	723	0	0.76	0.26	0.00	0.80
2037	365	2007	702	0	0.73	0.26	0.00	0.78
2038	365	1946	681	0	0.71	0.25	0.00	0.75
2039	365	1889	661	0	0.69	0.24	0.00	0.73
2040	366	1829	640	0	0.67	0.23	0.00	0.71
2041	365	1783	624	0	0.65	0.23	0.00	0.69
Total					**25.08**	**8.78**	**0.00**	**26.64**

Table 9 Tchendo, Technical Production Profile 2C resources. Production commencing July 2020

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	0	0	0	0	0	0	0
2019	365	0	0	0	0	0	0	0
2020	366/2	1561	546375	0	0.28	0.10	0	0.30
2021	365	2218	776321	0	0.81	0.28	0	0.86
2022	365	2718	951424	0	0.99	0.35	0	1.05
2023	365	2434	851929	0	0.89	0.31	0	0.94
2024	366	2192	767266	0	0.80	0.28	0	0.85
2025	365	1985	694626	0	0.72	0.25	0	0.77
2026	365	1805	631835	0	0.66	0.23	0	0.70
2027	365	1649	577190	0	0.60	0.21	0	0.64
2028	366	1512	529340	0	0.55	0.19	0	0.59
2029	365	1392	487204	0	0.51	0.18	0	0.54
2030	365	1285	449906	0	0.47	0.16	0	0.50
2031	365	1191	416733	0	0.43	0.15	0	0.46
2032	366	1106	387099	0	0.40	0.14	0	0.43
2033	365	1030	360517	0	0.38	0.13	0	0.40
2034	365	962	336582	0	0.35	0.12	0	0.37
2035	365	900	314955	0	0.33	0.11	0	0.35
2036	366	844	295347	0	0.31	0.11	0	0.33
2037	365	793	277514	0	0.29	0.10	0	0.31
2038	365	746	261250	0	0.27	0.10	0	0.29
2039	365	704	246374	0	0.26	0.09	0	0.27
2040	366	665	232734	0	0.24	0.08	0	0.26
2041	365	629	220196	0	0.23	0.08	0	0.24
Total					**10.78**	**3.77**	**0.00**	**11.46**

Tchibeli

Table 10 Tchibeli, Technical Production Profile P90. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	2750	756	0	1.00	0.28	0.00	1.05
2019	365	2460	677	0	0.90	0.25	0.00	0.94
2020	366	2176	598	0	0.80	0.22	0.00	0.84
2021	365	1935	532	0	0.71	0.19	0.00	0.74
2022	365	1717	472	0	0.63	0.17	0.00	0.66
2023	365	1522	419	0	0.56	0.15	0.00	0.58
2024	366	1347	370	0	0.49	0.14	0.00	0.52
2025	365	1198	329	0	0.44	0.12	0.00	0.46
2026	365	1062	292	0	0.39	0.11	0.00	0.41
2027	365	942	259	0	0.34	0.09	0.00	0.36
2028	366	833	229	0	0.30	0.08	0.00	0.32
2029	365	741	204	0	0.27	0.07	0.00	0.28
2030	365	657	181	0	0.24	0.07	0.00	0.25
2031	365	583	160	0	0.21	0.06	0.00	0.22
2032	366	516	142	0	0.19	0.05	0.00	0.20
2033	365	459	126	0	0.17	0.05	0.00	0.18
2034	365	407	112	0	0.15	0.04	0.00	0.16
2035	365	361	99	0	0.13	0.04	0.00	0.14
2036	366	319	88	0	0.12	0.03	0.00	0.12
2037	365	284	78	0	0.10	0.03	0.00	0.11
2038	365	252	69	0	0.09	0.03	0.00	0.10
2039	365	223	61	0	0.08	0.02	0.00	0.09
2040	366	197	54	0	0.07	0.02	0.00	0.08
2041	365	176	48	0	0.06	0.02	0.00	0.07
Total					**8.44**	**2.32**	**0.00**	**8.86**

Table 11 Tchibeli, Technical Production Profile P50. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	2763	760	0	1.01	0.28	0.00	1.06
2019	365	2535	697	0	0.93	0.25	0.00	0.97
2020	366	2312	636	0	0.85	0.23	0.00	0.89
2021	365	2129	585	0	0.78	0.21	0.00	0.82
2022	365	1962	539	0	0.72	0.20	0.00	0.75
2023	365	1813	499	0	0.66	0.18	0.00	0.69
2024	366	1677	461	0	0.61	0.17	0.00	0.64
2025	365	1563	430	0	0.57	0.16	0.00	0.60
2026	365	1457	401	0	0.53	0.15	0.00	0.56
2027	365	1361	374	0	0.50	0.14	0.00	0.52
2028	366	1271	350	0	0.47	0.13	0.00	0.49
2029	365	1196	329	0	0.44	0.12	0.00	0.46
2030	365	1125	309	0	0.41	0.11	0.00	0.43
2031	365	1059	291	0	0.39	0.11	0.00	0.41
2032	366	997	274	0	0.36	0.10	0.00	0.38
2033	365	945	260	0	0.34	0.09	0.00	0.36

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
2034	365	894	246	0	0.33	0.09	0.00	0.34
2035	365	848	233	0	0.31	0.09	0.00	0.32
2036	366	803	221	0	0.29	0.08	0.00	0.31
2037	365	765	210	0	0.28	0.08	0.00	0.29
2038	365	728	200	0	0.27	0.07	0.00	0.28
2039	365	694	191	0	0.25	0.07	0.00	0.27
2040	366	660	182	0	0.24	0.07	0.00	0.25
2041	365	632	174	0	0.23	0.06	0.00	0.24
Total					**11.76**	**3.23**	**0.00**	**12.33**

Table 12 Tchibeli, Technical Production Profile P10. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	2776	763	0	1.01	0.28	0.00	1.06
2019	365	2604	716	0	0.95	0.26	0.00	1.00
2020	366	2435	670	0	0.89	0.25	0.00	0.93
2021	365	2298	632	0	0.84	0.23	0.00	0.88
2022	365	2170	597	0	0.79	0.22	0.00	0.83
2023	365	2056	565	0	0.75	0.21	0.00	0.79
2024	366	1948	536	0	0.71	0.20	0.00	0.75
2025	365	1860	512	0	0.68	0.19	0.00	0.71
2026	365	1776	488	0	0.65	0.18	0.00	0.68
2027	365	1699	467	0	0.62	0.17	0.00	0.65
2028	366	1624	446	0	0.59	0.16	0.00	0.62
2029	365	1563	430	0	0.57	0.16	0.00	0.60
2030	365	1503	413	0	0.55	0.15	0.00	0.58
2031	365	1447	398	0	0.53	0.15	0.00	0.55
2032	366	1392	383	0	0.51	0.14	0.00	0.53
2033	365	1347	371	0	0.49	0.14	0.00	0.52
2034	365	1302	358	0	0.48	0.13	0.00	0.50
2035	365	1260	347	0	0.46	0.13	0.00	0.48
2036	366	1218	335	0	0.45	0.12	0.00	0.47
2037	365	1184	326	0	0.43	0.12	0.00	0.45
2038	365	1149	316	0	0.42	0.12	0.00	0.44
2039	365	1116	307	0	0.41	0.11	0.00	0.43
2040	366	1082	298	0	0.40	0.11	0.00	0.42
2041	365	1056	290	0	0.39	0.11	0.00	0.40
Total					**14.56**	**4.00**	**0.00**	**15.27**

Table 13 Tchibeli, Technical Production Profile 2C resources.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	0	0	0	0	0	0	0
2019	365	0	0	0	0	0	0	0
2020	365/2	976	268309	0	0.18	0.05	0	0.19
2021	365	1386	381229	0	0.51	0.14	0	0.53
2022	365	1699	467217	0	0.62	0.17	0	0.65
2023	365	1521	418358	0	0.56	0.15	0	0.58

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
2024	366	1370	376782	0	0.50	0.14	0	0.52
2025	365	1240	341111	0	0.45	0.12	0	0.47
2026	365	1128	310276	0	0.41	0.11	0	0.43
2027	365	1031	283441	0	0.38	0.10	0	0.39
2028	366	945	259944	0	0.35	0.09	0	0.36
2029	365	870	239252	0	0.32	0.09	0	0.33
2030	365	803	220936	0	0.29	0.08	0	0.31
2031	365	744	204646	0	0.27	0.07	0	0.28
2032	366	691	190093	0	0.25	0.07	0	0.26
2033	365	644	177040	0	0.23	0.06	0	0.25
2034	365	601	165286	0	0.22	0.06	0	0.23
2035	365	562	154665	0	0.21	0.06	0	0.22
2036	366	527	145036	0	0.19	0.05	0	0.20
2037	365	496	136279	0	0.18	0.05	0	0.19
2038	365	467	128292	0	0.17	0.05	0	0.18
2039	365	440	120987	0	0.16	0.04	0	0.17
2040	366	416	114289	0	0.15	0.04	0	0.16
2041	365	393	108132	0	0.14	0.04	0	0.15
Total					**6.74**	**1.85**	**0.00**	**7.07**

Litanzi

Table 14 Litanzi, Technical Production Profile P90. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	1311	879	0	0.48	0.32	0.00	0.54
2019	365	1050	704	0	0.38	0.26	0.00	0.43
2020	366	824	552	0	0.30	0.20	0.00	0.34
2021	365	650	435	0	0.24	0.16	0.00	0.27
2022	365	511	342	0	0.19	0.13	0.00	0.21
2023	365	402	269	0	0.15	0.10	0.00	0.16
2024	366	315	211	0	0.12	0.08	0.00	0.13
2025	365	249	167	0	0.09	0.06	0.00	0.10
2026	365	196	131	0	0.07	0.05	0.00	0.08
2027	365	154	103	0	0.06	0.04	0.00	0.06
2028	366	121	81	0	0.04	0.03	0.00	0.05
2029	365	95	64	0	0.03	0.02	0.00	0.04
2030	365	75	50	0	0.03	0.02	0.00	0.03
2031	365	59	39	0	0.02	0.01	0.00	0.02
2032	366	46	31	0	0.02	0.01	0.00	0.02
2033	365	36	24	0	0.01	0.01	0.00	0.01
2034	365	29	19	0	0.01	0.01	0.00	0.01
2035	365	23	15	0	0.01	0.01	0.00	0.01
2036	366	18	12	0	0.01	0.00	0.00	0.01
2037	365	14	9	0	0.01	0.00	0.00	0.01
2038	365	11	7	0	0.00	0.00	0.00	0.00
2039	365	9	6	0	0.00	0.00	0.00	0.00
2040	366	7	5	0	0.00	0.00	0.00	0.00
2041	365	5	4	0	0.00	0.00	0.00	0.00

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
Total					**2.27**	**1.52**	**0.00**	**2.54**

Table 15 Litanzi, Technical Production Profile P50. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	1321	885	0	0.48	0.32	0.00	0.54
2019	365	1107	741	0	0.40	0.27	0.00	0.45
2020	366	926	620	0	0.34	0.23	0.00	0.38
2021	365	790	530	0	0.29	0.19	0.00	0.32
2022	365	681	456	0	0.25	0.17	0.00	0.28
2023	365	593	397	0	0.22	0.14	0.00	0.24
2024	366	519	348	0	0.19	0.13	0.00	0.21
2025	365	461	309	0	0.17	0.11	0.00	0.19
2026	365	411	275	0	0.15	0.10	0.00	0.17
2027	365	368	247	0	0.13	0.09	0.00	0.15
2028	366	331	222	0	0.12	0.08	0.00	0.14
2029	365	301	202	0	0.11	0.07	0.00	0.12
2030	365	274	184	0	0.10	0.07	0.00	0.11
2031	365	251	168	0	0.09	0.06	0.00	0.10
2032	366	230	154	0	0.08	0.06	0.00	0.09
2033	365	212	142	0	0.08	0.05	0.00	0.09
2034	365	196	132	0	0.07	0.05	0.00	0.08
2035	365	182	122	0	0.07	0.04	0.00	0.07
2036	366	169	113	0	0.06	0.04	0.00	0.07
2037	365	158	106	0	0.06	0.04	0.00	0.06
2038	365	147	99	0	0.05	0.04	0.00	0.06
2039	365	138	92	0	0.05	0.03	0.00	0.06
2040	366	129	86	0	0.05	0.03	0.00	0.05
2041	365	122	82	0	0.04	0.03	0.00	0.05
Total					**3.66**	**2.45**	**0.00**	**4.10**

Table 16 Litanzi, Technical Production Profile P10. Basis for reserves calculation.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	1330	891	0	0.49	0.33	0.00	0.54
2019	365	1156	775	0	0.42	0.28	0.00	0.47
2020	366	1010	677	0	0.37	0.25	0.00	0.41
2021	365	901	604	0	0.33	0.22	0.00	0.37
2022	365	811	544	0	0.30	0.20	0.00	0.33
2023	365	738	494	0	0.27	0.18	0.00	0.30
2024	366	675	452	0	0.25	0.17	0.00	0.28
2025	365	625	419	0	0.23	0.15	0.00	0.26
2026	365	581	389	0	0.21	0.14	0.00	0.24
2027	365	542	363	0	0.20	0.13	0.00	0.22
2028	366	507	340	0	0.19	0.12	0.00	0.21
2029	365	478	321	0	0.17	0.12	0.00	0.20
2030	365	452	303	0	0.16	0.11	0.00	0.18
2031	365	428	287	0	0.16	0.10	0.00	0.17

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
2032	366	406	272	0	0.15	0.10	0.00	0.17
2033	365	388	260	0	0.14	0.09	0.00	0.16
2034	365	370	248	0	0.14	0.09	0.00	0.15
2035	365	354	237	0	0.13	0.09	0.00	0.14
2036	366	338	227	0	0.12	0.08	0.00	0.14
2037	365	326	218	0	0.12	0.08	0.00	0.13
2038	365	313	210	0	0.11	0.08	0.00	0.13
2039	365	302	202	0	0.11	0.07	0.00	0.12
2040	366	290	194	0	0.11	0.07	0.00	0.12
2041	365	281	188	0	0.10	0.07	0.00	0.11
Total					**4.97**	**3.33**	**0.00**	**5.56**

Table 17 Litanzi, Technical Production Profile 2C resources.

Year	Days	Oil (Rate)	Dry Gas (Rate)	NGL (Rate)	Oil (Volume)	Dry Gas (Volume)	NGL (Volume)	Annual Total (Volume)
		bbl/d	scf/d	boe/d	MMbbl	BScf	MMboe	MMboe
2018	365	0	0	0	0	0	0	0
2019	365	0	0	0	0	0	0	0
2020	366	1143	765897	0	0.21	0.14	0	0.23
2021	365	968	648570	0	0.35	0.24	0	0.40
2022	365	789	528374	0	0.29	0.19	0	0.32
2023	365	655	438757	0	0.24	0.16	0	0.27
2024	366	552	370157	0	0.20	0.14	0	0.23
2025	365	472	316479	0	0.17	0.12	0	0.19
2026	365	408	273688	0	0.15	0.10	0	0.17
2027	365	357	239026	0	0.13	0.09	0	0.15
2028	366	314	210557	0	0.11	0.08	0	0.13
2029	365	279	186888	0	0.10	0.07	0	0.11
2030	365	249	166997	0	0.09	0.06	0	0.10
2031	365	224	150122	0	0.08	0.05	0	0.09
2032	366	203	135681	0	0.07	0.05	0	0.08
2033	365	184	123229	0	0.07	0.04	0	0.08
2034	365	168	112415	0	0.06	0.04	0	0.07
2035	365	154	102965	0	0.06	0.04	0	0.06
2036	366	141	94659	0	0.05	0.03	0	0.06
2037	365	130	87319	0	0.05	0.03	0	0.05
2038	365	121	80800	0	0.04	0.03	0	0.05
2039	365	112	74986	0	0.04	0.03	0	0.05
2040	366	104	69777	0	0.04	0.03	0	0.04
2041	365	97	65093	0	0.04	0.02	0	0.04
Total					**2.6**	**1.77**	**0.00**	**2.96**

A3 - Cost Profiles

66All cost profiles have been provided by Petronor, reviewed by AGR and applied for reserves estimation. They are listed as gross numbers in 18MNOK. Note that the cost profiles are given independent of economic cut-off. No historic cost has been provided, hence uplift and depreciation is not included in the economic evaluation.

Tchibouela

Table 18 Tchibouela Cost Profiles

Cost Profiles (100%), R.T. MUSD 01.01.2018					
Year	**CAPEX**	**OPEX**	**Work-over cost**	**Tariff**	**Other cost**
2018	28	25	2	12	3
2019	28	25	2	11	3
2020		25	2	10	3
2021		25	2	9	3
2022		25	2	9	3
2023		25	2	8	3
2024		25	2	7	3
2025		25	2	7	3
2026		25	2	6	3
2027		25	2	6	3
2028		25	2	6	3
2029		25	2	5	3
2030		25	2	5	3
2031		25	2	5	3
2032		25	2	5	3
2033		25	2	4	3
2034		25	2	4	3
2035		25	2	4	3
2036		25	2	4	3
2037		25	2	4	3
2038		25	2	3	3
2039		25	2	3	3
2040		25	2	3	3
2041		25	2	3	3
Sum	**56**	**600**	**48**	**144**	**62**

Tchendo

Table 19 Tchendo Cost Profiles

Cost Profiles (100%), R.T. MUSD 01.01.2018					
Year	**CAPEX**	**OPEX**	**Work-over cost**	**Tariff**	**Other cost**
2018		9	1	5	0
2019		9	1	5	0
2020		9	1	5	0
2021		9	1	4	0
2022		9	1	4	0
2023		9	1	4	0
2024		9	1	3	0
2025		9	1	3	0
2026		9	1	3	0
2027		9	1	3	0
2028		9	1	3	0
2029		9	1	2	0
2030		9	1	2	0
2031		9	1	2	0
2032		9		2	0
2033		9		2	0
2034		9		2	0
2035		9		2	0
2036		9		2	0
2037		9		2	0
2038		9		1	0
2039		9		1	0
2040		9		1	0
2041		9		1	0
Sum		**216**	**14**	**66**	**4**

Tchibeli and Litanzi

Table 20 Tchibeli and Litanzi combined Cost Profiles

Cost Profiles (100%), R.T. MUSD 01.01.2018					
Year	CAPEX	OPEX	Work-over cost	Tariff	Other cost
2018		10	0	7	0
2019	12	10	0	7	0
2020		10	0	6	0
2021		10	0	5	0
2022		10	0	5	0
2023		10	0	4	0
2024		10	0	4	0
2025		10	0	4	0
2026		10	0	3	0
2027		10	0	3	0
2028		10	0	3	0
2029		10	0	3	0
2030		10	0	3	0
2031		10		2	0
2032		10		2	0
2033		10		2	0
2034		10		2	0
2035		10		2	0
2036		10		2	0
2037		10		2	0
2038		10		2	0
2039		10		2	0
2040		10		1	0
2041		10		1	0
Sum	**12**	**247**	**3**	**78**	**4**

A4 - Abbreviations

Abbreviation	Comment
%	Percentage
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resources
3C	High estimate of Contingent Resources
1P	Low estimate of Reserves (Proved Reserves)
2P	Best estimate of Reserves (Proved + Probable Reserves)
3P	High estimate of Reserves (Proved + Probable + Possible Reserves)
2D, 3D, 4D	Two Dimensional, Three Dimensional, Four Dimensional
B	(American) Billion (10^9)
bbl	Barrel
boe	Barrel of oil equivalent
BScf	Billion (10^9) standard cubic feet
CAPEX	Capital Expenditure
cP	Centipoise, physical unit for dynamic viscosity
DCA	Decline Curve Analysis
DST	Drill Stem Test (Production test)
ESP	Electrical Submersible Pump
EUR	Estimated Ultimate Recovery
ft	Foot
Fm	Formation
FPSO	Floating Production, Storage and Offloading
FVF	Formation Volume Factor
GIIP	Gas Initially In Place
GOC	Gas Oil Contact
GOR	Gas to Oil Ratio
HCPV	Hydro Carbon Pore Volume
K	Permeability
m	metre
MBAL	
mD	Milli (10^{-3}) Darcy
MD	Measured Depth
MMbbl	Million stock-tank barrels of oil
MMboe	Million barrels of oil equivalent
NGL	Natural Gas Liquids
NTG	Net To Gross
o.e.	Oil Equivalents
OCM	Operation Committe Meeting
OPEX	Operating Expenditure
OWC	Oil Water Contact
PHIE	Effective Porosity
PHIT	Total Porosity
PI	Productivity Index
PRMS	Petroleum Resource Management System
PV	Present Value
RF	Recovery Factor
Scf	Standard Cubic Feet
SEG	Society of Exploration Geophysicists
SEGY	File format for seismic data

Abbreviation	Comment
SPE	Society of Petroleum Engineers
STOIIP	Stock Tank Oil Initially In Place
Sw	Water Saturation
SWE	Effective Water Saturation
SWT	Total Water Saturation
TC	Technical Committe
TCM	Tecnical Committe Meeting
TD	True Depth
TVD	True Vertical Depth
TVDSS	True Vertical Depth Subsea
USD	US Dollars
WCT	Water Cut
WI	Water Injection

APPENDIX B:

UNAUDITED FINANCIAL STATEMENTS FOR PETRONOR FOR THE YEAR ENDED 31 DECEMBER 2017, UNAUDITED FINANCIALS FOR PETRONOR THE YEAR ENDED 31 DECEMBER 2018, AUDITED CONSOLIDATED FINANCIAL STATEMENTS FOR HEMLA AFRICA HOLDINGS AS OF 31 DECEMBER 2017 AND AUDITED FINANCIAL STATEMENTS FOR HEMLA E&P CONGO SA AS OF 31 DECEMBER 2017

ANNUAL REPORT 2017

PETRONOR E&P

(formerly PetroHemla Ltd)

CONTENTS

COMPANY AT A GLANCE

KEY FIGURES	2017
EBITDA (USD mill.)	37.32
EBIT (USD mill.)	34.81
Net profit / (loss) (USD mill.)	11.15
2P Reserves (MMbbl)	9.32
2C Contingent Resources (MMbbl)	7.63

2017 HIGHLIGHTS AND SUBSEQUENT EVENTS

- PetroNor E&P Ltd ("PetroNor" or the "Company") was formally established in 2017 as a joint venture company / special vehicle between the founders, Petromal – Sole Proprietorship LLC ("Petromal") of Abu Dhabi and Nor Energy AS of Norway.
- In a tender process for the producing oil fields jointly named PNGF Sud, initiated in 2016 by the Ministry of Hydrocarbons in the Republic of Congo, our subsidiary, Hemla E&P Congo SA ("HEPCO"), was awarded a 20% participating interest in PNGF Sud while the French company Perenco took on the Operatorship and 40% interest of the same fields.
- When the new license partners took over PNGF Sud, the asset was marginally commercial with an oil production of c. 15,000 bopd, a high cost level and a continuous decline in the production combined with and oil price outlook of 30 – 40 USD/bbl. After the entry into the license from 1 January 2017, the production has been increased by 40%, costs have been reduced by 40% and the oil price have increased by 40%, thus the asset has been converted from a marginally commercial asset and into a strong cash-generating asset.
- PetroNor has also invested into business development in Nigeria to be prepared for the next expansion for the company through means of acquisition

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

OFFICES

The company has its registered address in Nicosia, maintains headquarters in Oslo and Abu Dhabi, and operational offices in Pointe-Noire and Lagos.

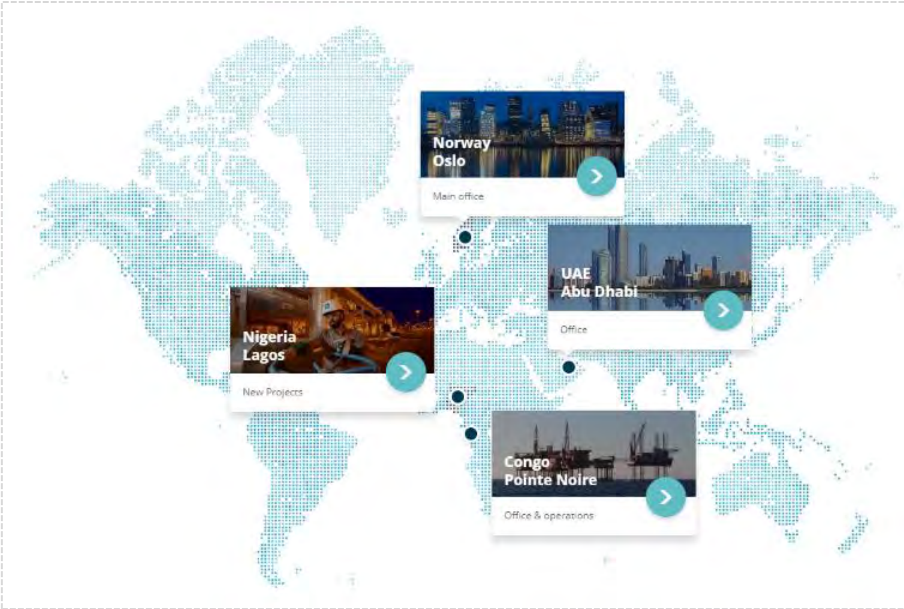

Figure 1

COMPANY STRUCTURE

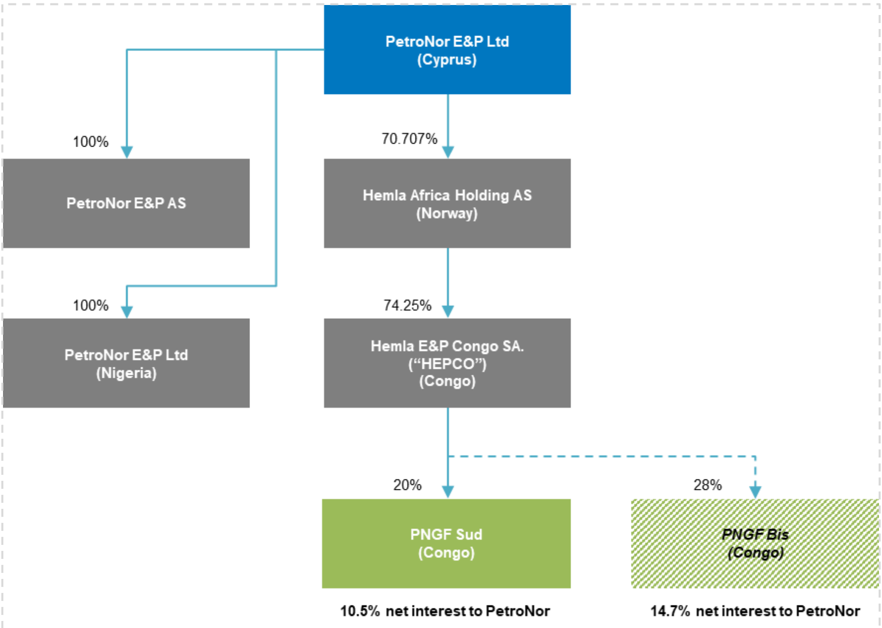

Figure 2

CEO LETTER

Dear Fellow Shareholders,

2017 was a historic year for PetroNor. It witnessed the emergence of PetroNor E&P in West Africa as a serious producer with solid expansion ambitions in the region.

In 2016, NOR Energy and Petromal started talks about a potential partnership in West Africa. The talks resulted in the first of its kind collaboration and partnership between Norwegian and UAE based E&P companies. This strong and unique partnership gave PetroNor E&P the strength, access and resources needed to participate in multiple bids in West Africa.

Our first successful bid was for PNGF Sud in Congo after ENI and Total decided to exit the license. Our award was for 20% of the license, which is operated by Perenco owning 40% of the lease. The lease award is for 20 years plus an option for 5 years extension.

Working and collaborating with Perenco resulted in significant achievements in increasing production while reducing cost. The field production increased from about 15,000 bopd to about 20,000 bopd. This increase in production was achieved while reducing the OPEX to 13 USD per barrel and the breakeven cost to 20-25 USD per barrel.

PetroNor maintained focus on West Africa and planned to capitalize on the Congo success and leverage our production to enhance shareholder value. PetroNor achieved a stable and very cost effective off-take agreement since production start-up, initially with TOTSA (Total Oil Trading) and currently with ENI.

For 2018, PetroNor has initiated discussions with multiple potential partners and identified excellent opportunities that will potentially further enhance shareholders value.

One major opportunity worth mentioning in this report is the potential farm in deal in a producing asset in Nigeria which would give us access to vast gas resource to be developed jointly with one of the most stable operators in Nigeria.

Our near term mission is to enhance our financing structure and avail more efficient financing for future opportunities. This will be key for our ambitious growth in the region.

On behalf of the management team, I would like to thank the shareholders for their trust and commitment.

Knut Søvold
CEO, PetroNor E&P

COMPANY OPERATIONS

PetroNor E&P has producing assets in West Africa, namely the PNGF Sud group of licenses in the Republic of Congo, and the right to enter into good faith negotiations alongside its partners in PNGF Sud for the license terms of the neighbouring PNGF Bis license.

PNGF SUD

PNGF Sud comprises 3 production sharing contracts (in French "Contrat de Partage de Production" or "CPP"): Tchibouela II, Tchendo II and Tcibeli-Litanzi II. The licenses cover five oil fields: Tchibouela Main, Tchibouela East, Tchendo, Tchibeli and Litanzi, which have been developed as a an integrated group named PNGF Sud. The licenses are located approximately 25 km off the coast of Pointe-Noire in water depths of 80-100 metres.

PetroNor, through Hemla E&P Congo, participated in the 2016 tender process with the Congo Ministry of Hydrocarbons for participation in the PNGF Sud licence. With effect from 1 of January 2017, HEPCO was awarded a 20% working interest in the PNGF Sud (net 10.5% to PetroNor). The National Assembly / Senate formally approved the license contracts on 24 May 2017 and subsequently made public 25 May 2017.

Initially discovered in 1979, PNGF Sud commenced production in 1987 and produced approx. 17,700 bopd gross from four oil fields, Tchibouela, Tchendo, Tchibeli and Litanzi in 2017. Following the entry of the new licence group in 2017, significant operational improvements have been made, increasing gross production from c. 15,000 bopd in January 2017 to today's level of approx. 21,600 bopd (post reporting period note; 2018). Through further work-overs, surface and process improvements and infill drilling, gross production from PNGF Sud is expected to continue to grow in the coming years.

The PNGF Sud fields are developed with seven wellhead platforms and currently produce from more than 50 active production wells, with oil exported via the onshore Djeno terminal (Tchibouela, Tchendo and Tchibeli) and the Nkossa FPSO (Litanzi). With its long production history, substantial well count and extensive infrastructure, PNGF Sud offers well diversified and low risk production and reserves with low break-even cost.

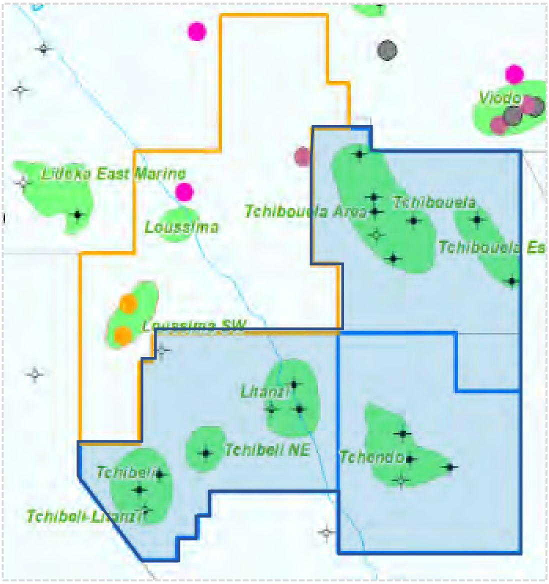

Figure 3 – PNGF Sud (blue border)

In 2018, AGR Petroleum Services ("AGR") prepared a Competent Person's Report ("CPR") (dated 30 October 2018 with volumes evaluated as of 31 December 2017) according to which PNGF Sud is estimated to hold net 2P reserves of 9.32 MMbbl and 2C contingent resources of 3.38 MMbbl.

During 2017, the gross production was 6.46 MMbbl of oil and 3.05 bcf of gas, corresponding to a net to PetroNor of 0.74 MMboe.

PNGF BIS

PNGF Bis is located to the North-West of PNGF Sud and comprises 2 fields: 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. Subject to successful completion of negotiations, PetroNor is expected to hold a 14.7% indirect interest.

Three exploration wells have been drilled on the licence area. A discovery in pre-salt Vandji Fm was made in well LUSM-1 on Loussima in 1985.

Loussima SW was discovered by well LUSOM-1 in 1987 with oil in Vandji Fm.

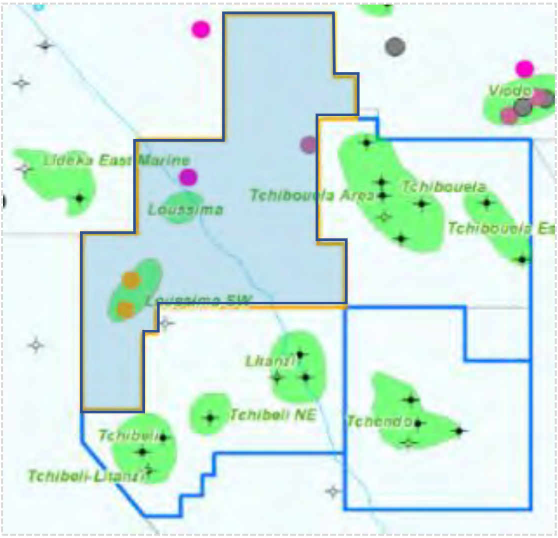

Figure 4 – PNGF Bis (orange border)

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, Sendji around 1,940 mVDSS and the water depth in the area is 110 m. DSTs 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 approx. 28.9 MMbbl.

FUTURE EXPANSION

The Company's vision is to be a full-cycle, Africa-focused E&P company focusing on producing assets with upside and development of stranded assets, combined with targeted high impact exploration. The Company aims to steadily build and increase its reserve base and production while using free cash flow to pursue defined exploration targets in selected and highly prospective basins with a view to delivering significant value to its shareholders from high impact wells.

In addition to entering PNGF Bis, pending successful negotiations of the license terms, PetroNor is looking at expanding its operations in West Africa within 2019. It is its intention to acquire one or more assets in Nigeria within the next 2 years. The target assets are proven and producing licenses with development and IOR potential. PetroNor is also looking at incorporating gas projects, particularly flared gas projects to LNG or power at a later stage.

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 in October 2018 for PNGF Sud and PNGF Bis. In addition, an assessment of the Proven Developed Producing (PDP) Reserves from each of the four fields prepared by Netherland Sewell and Associated Inc ("NSAI") in February 2018, is available to PetroNor.

PETRONOR ASSETS PORTFOLIO

As of 1 January 2017, HEPCO holds a 20% working interest in the three licenses Tchibouela II, Tchendo II and Tchibeli-Litanzi II (jointly the PNGF Sud licence). Through PetroNor's ownership of 52,5% of HEPCO, the 20% interest held by HEPCO corresponds to a net 10.5% interest to PetroNor (see Figure 2 explaining the ownership structure). Furthermore, the licence partnership has, through an umbrella agreement with the Ministry of Hydrocarbons, 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 HEPCO a 28% share in PNGF Bis, yielding an indirect 14.7% interest to PetroNor.

PNGF Sud: offshore Republic of 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 and with a 20% share by Hemla E&P Congo, constituting an indirect 10.5% share in the PNGF Sud license for the Company. The license ownership has been effective since 1 January 2017 with expiry date after 20 years plus a 5-year extension period. Since granting of the license, Perenco with partner support, has been committed to strict HSE compliance while growing production, improving maintenance routines and field integrity in a stepwise and prudent manner.

In October 2018 AGR performed a full Competent Persons Report covering the Reserves (1P, 2P and 3P) and Resources (1C, 2C and 3C) in both PNGF Sud and PNGF Bis. The figures included in this Annual Statement of Resources (ASR) are evaluated as of 31 December 2017.

Gross production during 2017 was 6.46 MMbbl of oil and 3.05 bcf of gas. This corresponds to average 17,700 bopd and 8.4 mmscfd of gas.

As per the PRMS/SPE guidelines, gas is included in the overall reserves in the AGR CPR as oil equivalents since 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.

This PetroNor ASR uses as the basis the Reserves and Resources from the 2018 October AGR CPR. As the only product sold is oil, PetroNor will in the text below when referring to Reserves and Resources mainly refer to oil and term these with the unit MMbbl.

As of 31 December 2017, AGR evaluated that gross 1P Proved Reserves yield 62.47 MMbbl in all the PNGF Sud fields in the Cenomanien and Turonian reservoirs. Gross 2P Proved plus Probable Reserves at PNGF Sud amounted to 88.75 MMbbl in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at PNGF Sud amounted to 107.44 MMbbl.

Gross 1C Resources yield 17.13 MMbbl in all the PNGF Sud fields in the Cenomanien and Turonian reservoirs. Gross 2C Resources at PNGF Sud amounted to 32.18 MMbbl in the same reservoirs. Gross 3C Resources at PNGF Sud amounted to 54.94 MMbbl.

These evaluations yield 1P Proved Reserves net to PetroNor of 6.56 MMbbl, 2P Proved plus Probable Reserves net to PetroNor of 9.32 MMbbl and 3P Proved plus Probable plus Possible Reserves net to PetroNor of 11.28 MMbbl. Additional potentially recoverable resources net to PetroNor are approximately 1.8 MMbbl 1C, 3.4 MMbbl 2C and 5.8 MMbbl 3C.

These Reserves and Contingent Resources are PetroNor's net volumes.

PNGF Bis: offshore Republic of Congo (Brazzaville), Operator Perenco, PetroNor 14.7%.

The PNGF Bis license neighbours the PNGF Sud license and contains two discoveries, Loussima 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.

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

MANAGEMENT DISCUSSION AND ANALYSIS

PetroNor uses the services of AGR Petroleum Services for 3rd party verifications of its reserves and resources. All evaluations are based on standard industry practice and methodology for production decline analysis and reservoir modelling based on geological and geophysical analysis. The following discussions lead up to the year-end 2017 ASR.

PNGF Sud: During 2017, 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 (ESP's), 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 to improve and enhance the production equipment and strengthening uptime while maintaining a strict HSE focus. Production levels during 2017 are approximately 17,700 bopd. Significant infill drilling potential has been identified in all fields. Resources identified as infill potential are classified as contingent resources as these are most likely not decided until the workover potential has been exhausted. These workovers are expected to continue in all fields throughout 2018.

A comparison of the AGR Proven (1P) reserves with the NSAI Proven Developed Producing (PDP) (1P Developed Producing) reserves shows NSAI PDP* reserves 15% less than AGR 1P.

*AGR – AGR Petroleum Services, 30 October 2018 (70 USD/bbl); NSAI – Netherland Sewell and Associates Inc., 28 February 2018 (54 USD/bbl).

The difference may be caused by the lack of emphasis on the current workover programme and/or different evaluation methods and oil price assumptions. By way of detail, the AGR CPR is significantly more comprehensive in terms of evaluation performed and reported.

2017 - Gross Proven Reserves (1P and PDP)

	AGR	NSAI	Difference
PNGF Sud	**1P (MMbbl)**	**PDP (MMbbl)**	**%**
Tchibouela	41.13	28.86	30%
Tchendo	10.63	10.96	-3%
Tchibeli	8.44	8.77	-4%
Litanzi	2.27	4.28	-88%
Total	**62.47**	**52.87**	**15%**

Oil only reserves per 31.12.2017

2017 - Net Proven Reserves (1P and PDP)

	AGR	NSAI	Difference
PNGF Sud (10.50%)	**1P (MMbbl)**	**PDP (MMbbl)**	**%**
Tchibouela	4.32	3.03	30%
Tchendo	1.12	1.15	-3%
Tchibeli	0.89	0.92	-4%
Litanzi	0.24	0.45	-88%
Total	**6.56**	**5.55**	**15%**

Net to PetroNor (10.5%)

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

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

2017 – 2P RESERVES	**(MMbbl)**
Balance (gross AGR, PNGF Sud – Dec 31, 2016)	95.21
Production 2017, PNGF Sud	(6.46)
Balance 31.12.2017 - 2P gross, PNGF Sud	88.75
Balance 31.12.2017 - 2P net, PNGF Sud	9.32

PetroNor's total 1P reserves at end of 2017 amount to 6.56 MMbbl according to the AGR assessment and 5.55 MMbbl according NSAI.

PetroNor's 2P reserves amount to 9.32 MMbbl and its 3P reserves amount to 11.28 MMbbl.

This reflects the October 2018 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 2017, PetroNor's assets contain a total 2C volume of approximately 7.6 MMbbl.

2P and 2C Reserves and Resources Status	**(MMbbl)**
Balance 31.12.2017 - 2P/2C gross, PNGF Sud	120.93
Balance 31.12.2017 - 2P/2C net, PNGF Sud	12.70
Balance 31.12.2017 - 2P/2C gross, Sud+Bis	149.83
Balance 31.12.2017 - 2P/2C net, Sud+Bis	16.95

ASSUMPTIONS

The commerciality and economic tests for the PNGF Sud and Bis reserves volumes were based on an oil and condensate price of 70 USD/bbl; the reserves and resources are not very sensitive to this parameter as OPEX levels are at 13 USD/bbl.

28 March 2019
Knut Søvold
CEO

Reserves and resources as per 31.12.2017 (AGR CPR dated 30.10.2018)

	Gross reserves									Gross Contingent Resources									Total Reserves and Resources								
	1P			2P			3P			1C			2C			3C			1P/1C			2P/2C			3P/3C		
PNGF Sud	Oil	Gas	Boe	**Oil**	**Gas**	**Boe**	Oil	Gas	Boe	Oil	Gas	Boe	**Oil**	**Gas**	**Boe**	Oil	Gas	Boe	Oil	Gas	Boe	**Oil**	**Gas**	**Boe**	Oil	Gas	Boe
	mmbo	bcf	mmboe	**mmbo**	**bcf**	**mmboe**	mmbo	bcf	mmboe	mmbo	bcf	mmboe	**mmbo**	**bcf**	**mmboe**	mmbo	bcf	mmboe	mmbo	bcf	mmboe	**mmbo**	**bcf**	**mmboe**	mmbo	bcf	mmboe
Tchibouela	41,13	16,78	44,12	52,49	21,42	56,30	62,83	25,63	67,39	6,20	2,50	6,65	12,00	4,9	12,87	20,70	8,40	22,20	47,33	19,28	50,76	64,49	26,32	69,18	83,53	34,03	89,59
Tchendo	10,63	3,72	11,29	20,84	7,29	22,14	25,08	8,78	26,64	5,60	2,00	5,96	10,80	3,8	11,48	17,84	6,24	18,95	16,23	5,72	17,25	31,64	11,09	33,62	42,92	15,02	45,59
Tchibeli	8,44	2,32	8,85	11,76	3,23	12,34	14,56	4,00	15,27	3,95	1,08	4,14	6,74	1,9	7,08	11,40	3,10	11,95	12,39	3,40	13,00	18,50	5,13	19,41	25,96	7,10	27,22
Litanzi	2,27	1,52	2,54	3,66	2,45	4,10	4,97	3,33	5,56	1,38	0,85	1,53	2,64	1,8	2,96	5,00	3,40	5,61	3,65	2,37	4,07	6,30	4,25	7,06	9,97	6,73	11,17
Total	62,47	24,34	66,80	88,75	34,39	94,87	107,44	41,74	114,87	17,13	6,43	18,28	32,18	12,40	34,39	54,94	21,14	58,70	79,60	30,77	85,08	120,93	46,79	129,26	162,38	62,88	173,58
PNGF Bis																											
Loussima (Bis)										22,40	0,00	22,40	28,90	0	28,90	35,80	0,00	35,80	22,40	0,00	22,40	28,90	0,00	28,90	35,80	0,00	35,80
Total	62,47	24,34	66,80	88,75	34,39	94,87	107,44	41,74	114,87	39,53	6,43	40,68	61,08	12,40	63,29	90,74	21,14	94,50	102,00	30,77	107,48	149,83	46,79	158,16	198,18	62,88	209,38

Net to Petronor - Reserves and resources as per 31.12.2017 (AGR CPR dated 30.10.2018 at the current Petronor indirect equity interest)

		Net PetroNor reserves									Net PetroNor Contingent Resources									Total net Petronor Reserves and Resources								
		1P			2P			3P			1C			2C			3C			1P/1C			2P/2C			3P/3C		
PNGF Sud	10,50 %	Oil	Gas	Boe	**Oil**	**Gas**	**Boe**	Oil	Gas	Boe	Oil	Gas	Boe	**Oil**	**Gas**	**Boe**	Oil	Gas	Boe	Oil	Gas	Boe	**Oil**	**Gas**	**Boe**	Oil	Gas	Boe
		mmbo	bcf	mmboe	**mmbo**	**bcf**	**mmboe**	mmbo	bcf	mmboe	mmbo	bcf	mmboe	**mmbo**	**bcf**	**mmboe**	mmbo	bcf	mmboe	mmbo	bcf	mmboe	**mmbo**	**bcf**	**mmboe**	mmbo	bcf	mmboe
Tchibouela		4,32	1,76	4,63	5,51	2,25	5,91	6,60	2,69	7,08	0,65	0,26	0,70	1,26	0,51	1,35	2,17	0,88	2,33	4,97	2,02	5,33	6,77	2,76	7,26	8,77	3,57	9,41
Tchendo		1,12	0,39	1,19	2,19	0,77	2,32	2,63	0,92	2,80	0,59	0,21	0,63	1,13	0,40	1,21	1,87	0,66	1,99	1,70	0,60	1,81	3,32	1,16	3,53	4,51	1,58	4,79
Tchibeli		0,89	0,24	0,93	1,23	0,34	1,30	1,53	0,42	1,60	0,41	0,11	0,43	0,71	0,20	0,74	1,20	0,33	1,25	1,30	0,36	1,36	1,94	0,54	2,04	2,73	0,75	2,86
Litanzi		0,24	0,16	0,27	0,38	0,26	0,43	0,52	0,35	0,58	0,14	0,09	0,16	0,28	0,19	0,31	0,53	0,36	0,59	0,38	0,25	0,43	0,66	0,45	0,74	1,05	0,71	1,17
Total		6,56	2,56	7,01	9,32	3,61	9,96	11,28	4,38	12,06	1,80	0,68	1,92	3,38	1,30	3,61	5,77	2,22	6,16	8,36	3,23	8,93	12,70	4,91	13,57	17,05	6,60	18,23
PNGF Bis	14,70 %																											
Loussima (Bis)											3,29		3,29	4,25	0	4,25	5,26		5,26	3,29		3,29	4,25		4,25	5,26		5,26
Total		6,56	2,56	7,01	9,32	3,61	9,96	11,28	4,38	12,06	5,09	0,68	5,21	7,63	1,30	7,86	11,03	2,22	11,43	11,65	3,23	12,23	16,95	4,91	17,82	22,31	6,60	23,49

Oil equivalents 5,615 mscf/boe

Figure 5 – Reserves and resources 2017

OPERATIONS

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

Initially discovered in 1979, PNGF Sud commenced production in 1987 and was producing approx. 17,700 bopd gross from four oil fields, Tchibouela, Tchendo, Tchibeli and Litanzi in 2017. Following the entry of the new licence group in 2017, significant operational improvements have been made, increasing gross production from c. 15,000 bopd in January 2017 to today's level of approx. 21,600 bopd (post reporting period note; 2018). Through further work-overs, surface and process improvements and infill drilling, gross production from PNGF Sud is expected to continue to grow in the coming years.

The PNGF Sud fields are developed with seven wellhead platforms and currently produce from more than 50 active production wells, with oil exported via the onshore Djeno terminal (Tchibouela, Tchendo and Tchibeli) and the Nkossa FPSO (Litanzi). With its long production history, substantial well count and extensive infrastructure, PNGF Sud offers well diversified and low risk production and reserves with low break-even cost.

In 2018, AGR Petroleum prepared a Competent Person's Report (the estimate is dated 30 October 2018 with volumes evaluated as of 31 of December 2017) according to which PNGF Sud is estimated to hold net 2P reserves of 9.32 MMbbl and 2C contingent resources of 3.38 MMbbl.

During 2017, the gross production was 6.46 MMbbl of oil and 3.05 bcf of gas, resulting in a net to PetroNor of 0.74 MMboe.

PNGF BIS

PNGF Bis is located to the North-West of PNGF Sud and comprises of 2 fields: 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. Subject to successful completion of negotiations, PetroNor is expected to hold a 14.7% indirect interest.

Three exploration wells have been drilled on the licence area. A discovery in pre-salt Vandji Fm was made in well LUSM-1 on Louossima 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 approx. 28.9 MMbbl.

THE ACCOUNTS

The Board confirms that the annual financial statements have been prepared pursuant to the going concern assumption, and that this assumption was realistic as at the balance sheet date. The going concern assumption is based upon the financial position of the Company and the development plans currently in place. In the Board of Directors' view, the annual accounts give a true and fair view of the group's assets and liabilities, financial position and results. PetroNor E&P Ltd. is the parent company of the PetroNor Group. Its financial statements have been prepared on the assumption that PetroNor will continue as a going concern.

The Company had USD 8.1 million in cash and bank balances as of 31 December 2017. Due to increase in production in PNGF a substantive increase is expected in existing revenue interest for the remainder of 2018.

PetroNor E&P Ltd. prepares its financial statements in accordance with the International Financial Reporting Standards (IFRS), as provided for by the EU. The consolidated accounts are presented in US dollars.

FINANCIAL PERFORMANCE AND ACTIVITIES

Condensed Consolidated Income Statement	*USD Million*
Oil and gas revenue	57.94
Cost of sales	(17.19)
Gross profit	**40.75**
General and administrative expenses	(3.43)
EBITDA	**37.32**
Depreciation and amortization	(2.51)
EBIT	**34.81**
Net financial items	(1.03)
Profit before taxes	**33.77**
Income tax	(22.62)
Net Profit	**11.15**
Attributable to:	
arents	5.85
NCI	5.30
	11.15

Despite being the first year the Company reported a profit after tax of USD 11.15 Million out of which USD 5.85 Million is attributable to the Parent Company and the rest is attributable to other non-controlling interests.

Oil & gas revenue in the year was (net of royalties & taxes) of USD 35 Million from sale of 0.63 Million barrels of crude oil at an average price of USD 56.05 per barrel. This is expected to increase in next year as the production levels are increasing in the PNGF SUD.

GP Margin and EBITDA margin of 43% and 34% respectively, is also expected to increase in the next year because of cost controlling measures implemented by the operator and the Group. 2017 was the first year of operations hence a higher costs were incurred but these will be normalize in the coming years.

Condensed Consolidated Statement of Financial Position	*USD Million*
ASSETS	
Non-current assets	17.31
Current assets	17.48
Total assets	**34.79**
EQUITY AND LIABILITIES	
Equity - Parents	5.97
Equity - NCI	5.71
Total Equity	**11.68**
Non-current liabilities	12.67
Current liabilities	10.44
Total liabilities	**23.11**
Total equity and liabilities	**34.79**

Non-current assets of USD 17 Million, includes Tender costs, entry bonus and signature bonus paid for acquiring the share in PNGF SUD.

Condensed Consolidated Statement of Cash Flows	*USD Million*
Operating cash flows	14.44
Working capital changes	1.03
Cash flows from operations	**15.47**
Cash flows from investing activities	**(7.52)**
Cash flows from financing activities	**0.12**
Net cash generated during the year	**8.07**

ALLOCATION OF PROFITS AND LOSSES

Parent Company Financial Information	*USD Million*
Oil and gas revenue	-
Cost of sales	-
Gross profit	**-**
General and administrative expenses	(5.00)
EBITDA	**(5.00)**
Depreciation and amortization	-
EBIT	**(5.00)**
Net financial items	-
Profit before taxes	**(5.00)**
Income tax	-
Net Profit	**(5.00)**

FUNDING

The shareholders provided a shareholders loan of USD 10 million in cash in addition to in-kind contribution to the overall group to cover the farm-in fees and start-up costs. The initial loan facility was repaid during the year and replaced with a third party short term debt facility of USD 10 million from Rasmala (Dubai based investor group) with a two year term.

RISK FACTORS

Operational Risk Factors

The development of oil and gas fields in which the Company is involved is associated with technical risk, alignment in consortiums with regards to development plans, and on obtaining necessary licenses and approvals from the authorities. Disruptions of operations might lead to cost overruns and production shortfall, or delays compared to the schedules laid out by the operator of the fields. As a non-operator, the Company has limited influence on operational risks related to exploration and development of the licenses and fields in which it has interests.

The PNGF Sud licenses were developed since 1987 and thus significant caution has to be taken by the Operator to ensure that the old facilities are properly maintained.

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

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

Financial risk factors

The overall risk management program seeks to minimize the potential adverse effects of unpredictable fluctuations in financial and commodity markets on financial performance, i.e., risks associated with currency exposures, debt servicing and oil and gas prices. 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 Company is exposed to risk arising from currency exposure, primarily with respect to the

Norwegian Kroner (NOK), the US Dollar (USD), and, to a lesser extent, the Euro (EUR).

The Company currently has a debt facility with Rasmala and if the PetroNor Group wishes to target new projects, it needs to increase its debt facilities. 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, off-take prepayment structures, and the issuance of shares.

ORGANISATION AND HEALTH, SAFETY AND ENVIRONMENT (HSE)

The management of the Company is led by CEO Knut Søvold. Mr. Søvold has considerable experience from various positions in the international oil and gas industry both from a technical and managerial perspective. He is supported by Business Development Manager, Gerhard Ludvigsen, and Executive Chairman, Eyas Alhomouz.

In 2017, PetroNor has been employing 16 individuals (including part-time employees and consultants), most of which were based in Pointe-Noire. Further, a number of consultants and services providers were engaged on a need by need basis.

The Company emphasizes the importance of maintaining a good working environment in order to achieve Company goals and objectives. The objective is to create a constructive working environment characterized by a spirit where employees' ideas and initiatives are welcomed, founded on mutual trust between employees, management and the Board of Directors.

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 Company's objective for health, environment, safety and quality (HSEQ) is zero accidents and zero unwanted incidents in all activities. The Company 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.

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

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

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

As a non-operator, PetroNor is dependent on the efforts of the operators with respect to achieving physical results in the field. However, the Company 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 Company can influence the choice of technical solutions, vendors and quality of applied procedures and practices.

The Company'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 Company's knowledge, all operations have been conducted within the limits set by approved environmental regulatory authorities.

CORPORATE GOVERNANCE

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

PetroNor acknowledges that successful value-added business is profoundly dependent upon transparency and internal and external confidence and trust. PetroNor believes that this is achieved by building a solid reputation based on our financial performance, our values and by fulfilling our commitments. Thus, good corporate governance practices combined with PetroNor's Code of Conduct is an important tool in assisting the Board to ensure that we properly discharge our duty.

The composition of the Board ensures that the Board represents the common interests of all shareholders and meets the Company's need for expertise, experience, capacity and diversity. The members of the Board represent a range of experience including oil and gas, energy, banking and investment. The composition of the Board ensures that it can operate independently of any special interests. Members of the Board are elected for a period of two years. Recruitment of members of the Board will be phased so that the entire Board is not replaced at the same time. The Chairman of the Board of Directors is elected by the General Meeting.

The Board may be given a power of attorney by the General Meeting to issue new shares for specific purposes. Any decision to deviate from the principle of equal treatment by waiving the pre-emption rights of existing shareholders to subscribe for shares in the event of an increase in share capital will be made only if it is in the common interest of the shareholders and the Company.

The Company has not granted any loans or guarantees to anyone in the management or any of the Directors.

The Board acknowledges the Norwegian Code of Practice for Corporate Governance and the principle of comply or explain. The Company has implemented a policy for Ethical Code of Conduct and works diligently to comply with these guidelines. The full policy is enclosed in this annual report (see section Ethical Code of Conduct).

DISCRIMINATION AND EQUAL EMPLOYMENT OPPORTUNITIES

PetroNor is an equal opportunity employer, with an equality concept integrated in its human resources policies. A diversified working environment is embraced, and the Company'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 company 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.

75% of the employees were men and 25% women at the end of 2017.

DIRECTORS AND SHAREHOLDERS

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

EVENTS SUBSEQUENT TO REPORTING DATE AND OUTLOOK

On 21 March 2018, post period end, the Company had officially changed its registered name from

PetroHemla Ltd to its current name, PetroNor E&P Ltd.

On the operations side, the production in PetroNor's assets has increased due to the improvements implemented by the Operator from around 15,000 bopd at the beginning of 2017 to an average of approx. 20,220 bopd in 2018.

Further, negotiations for entering PNGF Bis are ongoing. From the PNGF Sud contractor group, only Perenco and HEPCO have opted to enter PNGF Bis alongside SNPC. Following successful negotiations of the terms of the PSC, the Company intends for HEPCO to enter into the license.

PetroNor looks forward to continued growth, where it can build upon its current operations and experienced team and capitalise on the strength of its shareholders and respective networks to expand its operations in West Africa.

Therefore, PetroNor has decided to proceed with a listing process on the Oslo Stock Exchange through a reverse take-over of London-based, African Petroleum LLC. African Petroleum LLC is also present in Africa, thus the Company believes there are strong synergies to be achieved for both through the reverse take-over.

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

28 March 2019
The Board of Directors
PetroNor E&P Ltd

Eyas Alhomouz	Knut Søvold	Gerhard Ludvigsen	Hawary Marshad
Chairman of the Board	CEO & Director	Director	Director

BOARD OF DIRECTORS AND SENIOR MANAGEMENT

Eyas Alhomouz (Chairman of the Board of Directors)

Mr. Alhomouz has a strong experience from the oil and gas sector covering the US, 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 a COO and Financial 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 a General Manager of Jaidah Energy, an Omani-Qatari owned company servicing the oil and gas sector in Qatar. Mr. Alhomouz graduated from Brigham Young University in Provo, UT with a degree in Chemical Engineering and from the Colorado School of Mines, in Golden, CO with a master's degree in Mineral and Energy Economics.

Knut Søvold (Director and Chief Executive Officer)

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

Gerhard Ludvigsen (Director and Business Development Manager)

Mr. Ludvigsen is the founder of several companies in Norway 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 Solution 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. He has recently established PetroNor E&P with Petromal which holds oil production in West Africa with focus on IOR development. He serves on the board of the charity foundation Power to Educate which supports education in emerging countries.

Hawary Marshad (Director)

Mr. Marshad graduated from the University of Houston in 1990 with his BBA, majoring in finance. He began his career in auditing at a public accounting firm in Dubai and earned his CPA in 1994. He worked at Ernst & Young for 11 years moving up to Executive Director the last three years there. Main areas of focus where audit, accounting, valuation and due diligence, consulting and internal audit services. From there, he moved into the industry and became the Head of Finance for a Saudi FMGC conglomerate, where he was a key member of senior management, including the acting COO for the last 18 months that he was there. After six years in Saudi, he moved back to Dubai and joined Zabeel Investment as the Group CFO. The company had significant investments in Real Estate, Private Equity and Capital Markets. He led the financial restructuring of the group and oversaw the completion of several key projects during a very turbulent time. After the restructuring of Zabeel, Hawary joined Deyaar, a fully integrated real estate development and management company, as the CFO, where he initiated a strategic five-year plan for the Company, with a focus on diversification to counter the cyclical nature of real estate. After Deyaar, he migrated to Canada for a couple of years, where he setup a consultancy company providing finance and accounting services and sourcing of investment opportunities. Mr. Marshad joined EIIC in February 2018 as the CFO. Under his current role, he leads the finance, accounting and treasury role, while working closely with the senior management of the group to provide support.

CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the year ended 31 December 2017

	Notes	2017 USD'000
Revenue, net of royalties	3	57,936
Cost of sales	4	(19,698)
GROSS PROFIT		38,238
General and administrative expenses	5	(3,428)
OPERATING PROFIT		34,810
Finance costs	6	(878)
Foreign exchange gain / (loss)		(157)
PROFIT BEFORE INCOME TAX		33,775
Income tax expense	7	(22,621)
PROFIT AND TOTOAL COMPREHENSIVE INCOME FOR THE YEAR		11,154
Attributable to:		
Equity holders of the parent		5,850
Non-controlling interest		5,304
		11,154

The attached notes 1 to 22 form part of these consolidated financial statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
At 31 December 2017

	Notes	**2017** **USD'000**
ASSETS		
Non-current assets		
Intangible assets		
License	8	**6,451**
Goodwill	9	**9**
		6,460
Tangible assets		
Production assets and equipment	10	**10,854**
		10,854
Total non-current assets		**17,314**
Current assets		
Inventory	11	**2,369**
Accounts receivable, deposits and prepayments	12	**7,043**
Cash and bank balances	13	**8,069**
Total current assets		**17,481**
TOTAL ASSETS		**34,795**
EQUITY AND LIABILITIES		
Equity		
Share capital	14	120
Retained earnings		5,850
		5,970
Non-controlling interest		5,713
Total equity		**11,683**
Non-current liability		
Decommissioning liability	15	**12,672**
Total non-current liabilities		**12,672**
Current liabilities		
Accounts payable and accrued liabilities	16	**10,440**
Total current liabilities		**10,440**
Total liabilities		23,112
TOTAL EQUITY AND LIABILITIES		**34,795**

Chief Executive Officer

Chief Financial Officer

The attached notes 1 to 22 form part of these consolidated financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

Year ended 31 December 2017

	Attributable to the equity holders of parent				
	Share capital USD'000	*Retained earnings USD'000*	*Total USD'000*	*Non - controlling interest USD'000*	*Total equity USD'000*
Balance at 1 January 2017	-	-	-	-	-
Share capital	120	-	120	-	120
Acquisition of a subsidiary	-	-	-	409	409
Total comprehensive income for the year	-	5,850	5,850	5,304	11,154
Balance at 31 December 2017	**120**	**5,850**	**5,970**	**5,713**	**11,683**

The attached notes 1 to 22 form part of these consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS
Year ended 31 December 2017

	Notes	2017 USD'000
OPERATING ACTIVITIES		
Profit before tax for the year		33,775
Adjustments for:		
Depreciation and amortization	8 & 10	2,511
Unwinding of discount on decommissioning liability	5	773
		36,882
Working capital adjustments:		
Inventories		(2,369)
Accounts receivable, deposits and prepayments		(7,043)
Accounts payable and accrued liabilities		10,440
		1,028
Tax paid	10	(22,621)
NET CASH FLOWS FROM OPERATING ACTIVITIES		15,466
INVESTING ACTIVITIES		
Investment in production & other assets		(7,917)
Acquisition of subsidiary, recognized goodwill		(9)
Proceeds from sale of non-controlling interest		409
NET CASH FLOWS FROM INVESTING ACTIVITIES		(7,517)
FINANCING ACTIVITIES		
Issued capital		120
NET CASH FLOWS FROM FINANCING ACTIVITIES		120
CHANGE IN CASH AND CASH EQUIVALENTS		8,069
Cash and cash equivalents at 1 January		-
CASH AND CASH EQUIVALENTS AT 31 DECEMBER		8,069

The attached notes 1 to 22 form part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

31 December 2017

1 COROPORATE INFORMATION

The consolidated financial statements of the Group, which comprise PetroNor E&P Ltd (PetroNor, as the parent) and all its subsidiaries, for the year ended 31 December 2017, were authorised for issue in accordance with a resolution of the directors on 28 March 2019. PetroNor is a private company limited by shares registered in the Republic of Cyprus under registration number HE 367916. PetroNor has its registered address at Arch. Makariou III, 42E Matina Court, 3rd floor, Office 303, 1065 Nicosia, Cyprus.

The principal activities of the Group are exploration and production of crude oil. Information on the Group's parent and other related party relationships is presented in Note 18.3.

2 BASIS OF PREPARATION AND OTHER SIGNIFICANT ACCOUNTING POLICIES

This section provides additional information about the overall basis of preparation that the directors consider is useful to be relevant in understanding these financial statements.

2.1 BASIS OF PREPARATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements have been prepared on a historical cost basis. The consolidated financial statements are presented in US dollars, and all values are rounded to the nearest thousand (USD 000), except where otherwise indicated.

2.2 BASIS OF COSOLIDATION

The consolidated financial statements comprise the financial statements of the Company and its following subsidiaries as at 31 December 2017.

Name of company	*Activities*	*Country of incorporation*	*Percentage holding*
Hemla Africa Holding AS	The company's business is to invest in companies and entities that are involved in the oil and gas industry nationally and internationally, as well as investment activities and other related activities, including project management.	Norway	**70.707%**
Hemla E&P Congo SA	Congolese subsidiary of the Company, holding the rights to the assets in Congo. HEPCO is active in the oil and gas industry as an E&P company.	Republic of Congo	**52.500%**

Hemla E&P Congo SA is owned 74.25% by Hemla Africa Holding AS and hence effectively owned 52.50% by the Company.

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.

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; and
- The Group's voting rights and potential voting rights

The relevant activities are those which significantly affect the subsidiary's returns. The ability to approve the operating and capital budget of a subsidiary and the ability to appoint key management personnel are decisions that demonstrate that the Group has the existing rights to direct the relevant activities of a subsidiary.

The Group re-assesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control.

Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of during the year are included in the statement of comprehensive income from the date the Group gains control until the date the Group ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income (OCI), where applicable, 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 interest;
- 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; and
- reclassifies the parent's share of components previously recognised in other comprehensive income 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.

2.3 SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

2.3.1 ESTIMATES AND ASSUMPTIONS

The preparation of the financial statements in conformity with IFRS as adopted by the EU requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities and contingent liabilities at the date of the consolidated financial statements and reported amounts of revenues and expenses during the reporting period. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However, actual outcomes can differ from these estimates.

In particular, significant areas of estimation uncertainty considered by management in preparing the consolidated financial statements are as follows:

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.

Income 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 from the Cyprus statutory tax rate 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.

2.3.2 JUDGEMENTS

In the process of applying the Group's accounting policies, the directors have made the following judgments, apart from those involving estimates, which have the most significant effect on the amounts recognised in the consolidated financial statements:

Impairment indicators
The Group assesses each cash-generating unit annually to determine whether an indication of impairment exists. When an indication of impairment exists, a formal estimate of the recoverable amount is made. The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell, or if relevant, a combination of these two models. These calculations require the use of estimates and assumptions. It is reasonably possible that the oil price assumption may change which may then impact the estimated life of the field and may then require a material adjustment to the carrying value of tangible assets. The Group monitors internal and external indicators of impairment relating to its tangible and intangible assets.

Technical risk in development of oil and gas fields
The development of the oil and gas fields, in which the Group has an ownership, is associated with significant technical risk and uncertainty with regards to timing of additional production from new development activities. Risks include, but are not limited to, cost overruns, production disruptions as well as delays compared to initial plans laid out by the operator. Some of the most important risk factors are related to the

determination of reserves, the recoverability of reserves, and the planning of a cost efficient and suitable production method. There are also technical risks present in the production phase that may cause cost overruns, failed investment and destruction of wells and reservoirs. Judgements have been made after taking into account information available to management and factors in unknown uncertainties as of the date of the balance sheet.

Asset retirement obligations
Asset retirement 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 asset retirement 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 asset retirement obligation. 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 asset retirement costs required.

Contingencies
By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

2.4 SUMAMRY OF SIGNIFICANT ACCOUNTING POLICIES

INTERESTS IN JOINT ARRANGEMENTS

A joint arrangement is an arrangement over which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities (being those that significantly affect the returns of the arrangement) require unanimous consent of the parties sharing control.

Joint operations
A joint operation is a type of joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities, relating to the arrangement. In relation to its interests in joint operations, the Group 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
- Expenses, including its share of any expenses incurred jointly.

FOREIGN CURRENCIES

The consolidated financial statements are presented in US dollars, which is also the Group's presentation currency. The functional currency of the Company is Euros and that of its subsidiaries are as follows:

- Hemla Africa Holding AS Norwegian Krone (NOK)
- Hemla E&P Congo S.A United States Dollars (USD)

Translation of foreign entities
The functional currency for each of the Company's subsidiaries and jointly-controlled operations is the currency of the primary economic environment in which it operates. Operations with foreign functional currencies are translated into US dollars in the following manner:

- Monetary and non-monetary assets and liabilities are translated at the rate of exchange in effect at the statement of financial position date;
- Revenue and expense items (including depletion, depreciation, and amortization) are translated at average rates of exchange prevailing during the year (as this is considered a reasonable approximation to actual rates); and
- Exchange gains and losses that result from the translation are recognized and disclosed as a cumulative translation adjustment in other comprehensive income/loss.

Translation of other foreign currency transactions and balances
Foreign currencies are translated into the functional currency as follows:

- Monetary assets and liabilities are translated at current rates of exchange;
- Non-monetary items are translated at historical exchange rates;
- Revenue and expense items are translated at the average rates of exchange; and
- Gains or losses resulting from these translation adjustments are recognized within net income (loss) in the consolidated statement of comprehensive income (loss).

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 IAS 39 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 IAS 39, it is measured in accordance with the appropriate IFRS. Contingent consideration that is classified as equity is not re-measured, 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.

LICENSE INTERESTS, AND FIELD INVESTMENTS, AND DEPRECIATION

Oil & gas production assets
Development and production assets are accumulated on a cash-generating unit basis and represent the cost of developing the commercial reserves discovered and bringing them into production together with E&E expenditures incurred in finding commercial reserves transferred from intangible E&E assets as outlined in accounting policy above.

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/amortisation
Oil and gas properties and intangible assets are depreciated or amortised using the unit-of-production method. Unit-of production rates are based on proved and probable 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.

FINANCIAL ASSETS

Initial recognition and measurement

Financial assets are classified, at initial recognition, as financial assets at fair value through profit or loss, loans and receivables, held-to-maturity investments, restricted cash, available-for-sale (AFS) financial assets, or derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial assets are recognised initially at fair value plus, in the case of financial assets not recorded at fair value through profit or loss, transaction costs that are attributable to the acquisition of the financial asset.

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

The Group's financial assets include cash and cash equivalents and certain trade and other receivables.

Subsequent measurement

For purposes of subsequent measurement financial assets are classified into four categories:

- Financial assets at fair value through profit or loss
- Trade and other receivables
- Held-to-maturity investments – the Group has no held-to-maturity investments
- AFS financial investments – the Group has no AFS financial assets

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss include financial assets held for trading and financial assets designated upon initial recognition at fair value through profit or loss. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives, are also classified as held for trading unless they are designated as effective hedging instruments, as defined by IAS 39. Financial assets at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value presented as finance costs (negative changes in fair value) or finance revenue (positive net changes in fair value) in the statement of comprehensive income. The Group has not designated any financial assets at fair value through profit or loss.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not held for trading or designated at fair value though profit or loss. These embedded derivatives are measured at fair value, with changes in fair value recognised in the statement of profit or loss and other comprehensive income. Reassessment occurs only if there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required or there is a reclassification of a financial asset out of the fair value through profit or loss category. The group has no embedded derivatives as of December 31, 2017.

Trade and other receivables

This category is most relevant to the Group. Trade and other receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, such financial assets are subsequently measured at amortised cost using the effective interest rate method, less impairment. 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 effective interest rate. The effective interest rate amortisation is included in finance income in the statement of profit or loss and other comprehensive income. The losses arising from impairment are recognised in the statement of profit or loss and other comprehensive income in finance costs for loans and in cost of sales or other operating expenses for receivables.

Cash and cash equivalents
Cash and cash equivalents includes cash at hand, and deposits held on call with banks. Cash balances in current accounts, short-term deposits and placement with maturity of six months or less in highly liquid investments are classified as cash and cash equivalents.

Impairment of financial assets
The Group assesses at each reporting date whether a financial asset or group of financial assets are impaired. Details of impairment principles for financial assets is included in note 2.4.

FINANCIAL LIABILITIES

Initial recognition and measurement
Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate.

All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The Group's financial liabilities include trade and other payables.

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

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

ASSET RETIREMENT OBLIGATION

An asset retirement 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 asset retirement, discounted to its present value. Changes in the estimated timing of asset retirement or asset retirement 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 asset retirement provision is included as a finance cost.

INCOME 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.

Production-sharing arrangements
According to the production-sharing arrangement (PSA) in certain licenses, 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 Group to the appropriate tax authorities. This portion of income tax and revenue are presented net in income statement.

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.

REVENUE RECOGNITION

Revenue from petroleum products
Revenue from the sale of petroleum products is recognized as income using the "entitlement method". Under this method, revenue is recorded on the basis of the asset's proportionate share of total crude, gas and NGL produced from the affected fields. Revenue is stated net of royalties.

IMPAIRMENTS OF NON-OIL AND GAS INTERESTS

Non-financial assets
Assets that are subject to amortisation or depreciation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Goodwill is assessed for impairment on an annual basis. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows (cash-generating units). Nonfinancial assets that were previously impaired are reviewed for possible reversal of the impairment at each reporting date.

A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years. Such a reversal is recognised in the income statement. After such a reversal the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Financial assets
Assets carried at amortised cost If there is objective evidence that an impairment loss on assets carried at amortised cost has been incurred, the amount of the loss is measured as the difference between the assets' carrying amount and the present value of estimated future cash flows (excluding future expected credit losses that have not been incurred) discounted at the financial asset's original effective interest rate (i.e. the effective interest rate computed at initial recognition). The carrying amount of the asset is reduced through use of an allowance account. The amount of the loss shall be recognised in the income statement.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognised, the previously recognised impairment loss is reversed, to the extent that the carrying value of the asset does not exceed its amortised cost at the reversal date, any subsequent reversal of an impairment loss is recognised in the income statement.

In relation to trade receivables, a provision for impairment is made when there is objective evidence (such as the probability of insolvency or significant financial difficulties of the debtor) that the Group will not be able to collect all of the amounts due under the original terms of the invoice. The carrying amount of the receivable is reduced through use of an allowance account. Impaired debts are derecognised when they are assessed as uncollectible.

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.

2.5 CHANGES IN ACCOUNTING POLICIES AND DISCLOSURES

New and amended standards and interpretations

The Group applied for the first time certain standards and amendments, which are effective for annual periods beginning on or after 1 January 2017. Although these new standards and amendments are applied for the first time in 2017, the application of these new standards and amendments, did not have a material impact on the annual financial statements of the Group. The nature and the impact of each new standard or amendment is described below:

- Amendments to IAS 7 Statement of Cash Flows: Disclosure Initiative
- Amendments to IAS 12 Income Taxes: Recognition of Deferred Tax Assets for Unrealised Losses

Annual Improvements 2014-2016 cycle:

- Amendments to IFRS 12 Disclosures of Interests in Other Entities: Clarification of the scope of disclosure requirements in IFRS 12

Adoption of the above amended IFRS and improvements to IFRS did not have any significant impact on the Group.

2.6 STANDARDS ISSUED BUT NOT YET EFFECTIVE

The standards and interpretations that are issued, but not yet effective, up to the date of issuance of the Group's financial statements are disclosed below. The Group intends to adopt these standards, if applicable, when they become effective.

- IFRS 2 Classification and Measurement of Share-based Payment Transactions — Amendments to IFRS 2
- Amendments to IFRS 4: Applying IFRS 9 Financial Instruments with IFRS 4 Insurance Contracts
- IFRS 9 Financial Instruments
- Amendments to IFRS 10 and IAS 28: Sale or Contribution of Assets between an Investor and its Associate or Joint Venture
- IFRS 15 Revenue from Contracts with Customers
- IFRS 16 Leases
- IFRS 17 Insurance Contracts
- Amendments to IAS 40: Transfers of Investment Property
- IFRS 22 Foreign Currency Transactions and Advance Consideration
- IFRIC 23 Uncertainty over Income Tax Treatments.

Annual Improvements 2014-2016 Cycle

- IFRS 1 First-time adoption of International Financial Reporting Standards – Deletion of short-term exemptions for first time adopters
- IAS 28 Investments in Associates and Joint Ventures – Clarification that measuring investees at fair value through profit or loss is an investment-by-investment choice
- IFRS 3 Business Combinations - Previously held interests in a joint operation
- IFRS 11 Joint Arrangements - Previously held interests in a joint operation
- IAS 12 Income Taxes - Income tax consequences of payments on financial instruments classified as equity
- IAS 23 Borrowing Costs - Borrowing costs eligible for capitalization

Management intends to adopt these standards and amendments, if applicable, when they become effective. Management has performed initial assessment of the impact of IFRS 9 and IFRS 15 on its financial statements. Management believes that the initial application of these standards will not have a significant impact on the financial statements.

3. REVENUE

Sales, net of royalties for the year ended 31 December 2017 were USD 57.94 million.

The quantity of oil lifted during the year for Equity is 0.63 million barrels which is translated into USD 35.32 million of revenue at an average price of USD 56.05 per barrel.

The revenue assigned for the tax is amounted to USD 22.62 million.

4. COST OF SALES

	Notes	2017 USD'000
Operating expenses		**19,043**
Depreciation and amortization of oil and gas properties	8 & 10	**2,511**
Movement in oil inventory		**(1,856)**
		19,698

5. GENERAL AND ADMINISTRATIVE EXPENSES

Personnel expenses	**944**
Travelling expenses	**800**
Business development expenses	**585**
Legal and professional expenses	**206**
Office rent	**157**
Other expenses	**737**
	3,429

5a. PERSONNEL EXPENSES

Salaries	**731**
Other compensation	**213**
	944

The Company didn't have any staff employed during the year, while average number of staff employed in Hemla E&P Congo was 9.

5b. MANAGEMENT REMUNERATION

Executive management consisted of the Chief Executive Officer (CEO). Executive management was not paid any remuneration during the year.

5c. BOARD OF DIRECTORS REMUNERATION

The remuneration of the members of the Board is determined on a yearly basis by the Company at its annual general meeting. The directors may also be reimbursed for, inter alia, travelling, hotel and other expenses incurred by them in attending meetings of the directors or in connection with the business of the Company. A director who has been given a special assignment, besides his/her normal duties as a director of the Board, in relation to the business of the Company may be paid such extra remuneration as the directors may determine.

There was no remuneration paid or accrued for the members of the Board for the year ended 31 December 2017.

5d. AUDITORS' REMUNERATION

Fees, excluding VAT, to the auditors are included in general and administrative expenses and are shown below:

	2017 USD'000
Ernst & Young	
Annual audit	28
Echas Revisjon AS	
Annual audit	3
	31

6. FINANCE COST

	Notes	2017 USD'000
Unwinding of discount on decommissioning liability	15	773
Interest expense		105
		878

7. INCOME TAX

Income tax expense for the year ended 31 December 2017 was USD 22.62 million. It was paid in shape of Oil at source.

8. LICENSES

USD'000	Total
2017	
Cost	
At 1 January 2017	-
Additions	7,382
At 31 December 2017	7,382
Amortization	
At 1 January 2017	-
Charge for the year	931
At 31 December 2017	931
Net carrying amount	
At 31 December 2017	6,451

9. ACQUISITION OF SUBSIDIARY

Upon establishment, the Company acquired 70.707% the share capital of Hemla Africa Holding AS (HAH AS). HAH AS' business is to invest in companies and entities that are involved in the oil and gas industry nationally and internationally, as well as investment activities and other related activities, including project management. It operates under organization number 999 077 013 in Norway issued 31 October 2012.

Assets acquired and liabilities assumed

The fair value of the identifiable assets and liabilities of HAH AS as at the dated of acquisition were as follows:

	Fair Value recognised on acquisition USD'000
Assets	
Bank	**5**
Total assets	**5**
Liabilities	
Accounts payable and accrued expenses	**15**
Total liabilities	**15**
Net assets acquired	**(10)**
70.707% shares acquired by the Company	**(7)**
Goodwill on acquisition	**9**
Total acquisition costs	**3**

The acquisition costs are settled through intercompany accounts.

10. PRODUCTION ASSETS AND EQUIPMENT

USD'000	**Production assets and equipment**	**Motor vehicles**	**Total**
2017			
Cost			
At 1 January 2017	-	-	**-**
Additions	12,425	9	**12,434**
At 31 December 2017	**12,425**	**9**	**12,434**
Depreciation			
At 1 January 2017	-	-	**-**
Charge for the year	1,571	9	**1,580**
At 31 December 2017	**1,571**	**9**	**1,580**
Net carrying amount			
At 31 December 2017	**10,854**	**-**	**10,854**

11. INVENTORIES

	2017 USD'000
Crude oil inventory	**1,856**
Materials and supplies	**513**
	2,369

The crude oil inventory and the material and supplies inventory are valued at the lower of cost and net realizable value. Cost is determined using the weighted average method. Net realizable 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. ACCOUNTS RECEIVABLE, DEPOSITS AND PREPAYMENTS

Due from related parties	**6,162**
Deposits	**31**
Prepayments	**17**
Other receivables	**833**
	7,043

13. CASH AND BANK BALANCES

Cash bank balances	
Cash and cash equivalents at 31 December	**8,069**

14. SHARE CAPITAL

Authorised, issued and fully paid 100,000 shares of € 1.00 each (USD 1.20 each)	**120**

15. ASSET RETIREMENT OBLIGATION

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 depend on the rate the reserves of the field are depleted. However, based on the existing production profile of the PNGF SUD field and the size of the reserves, it is expected that expenditure on retirement is likely to be after more than ten years. The current bases for the provision are a discount rate of 6.5% and an inflation rate of 1.6%. The 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:

	2017 USD'000
Balance, beginning of year	-
Arising during the year	**11,899**
Unwinding of discount on decommissioning	**773**
	12,672

16. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2017 USD'000
Trade payable	4,412
Due to related parties	2,518
Taxes and state payables	3,398
Other payables and accrued liabilities	112
	10,440

17. CONTINGENCIES AND COMMITMENTS

As at 31 December 2017, the Company has no financial contingent liabilities and commitments except those recognized in the normal course of business.

18. RELATED PARTY TRANSACTIONS

18.1 SUBSIDIARIES

Subsidiary	Place of incorporation	Ownership
PetroNor E&P AS	Norway	100% (direct)
PetroNor E&P Ltd	Nigeria	100% (direct)
Hemla Africa Holding AS	Norway	70.707% (direct)
Hemla E&P Congo S.A.	Republic of Congo	52.50% (indirect)

18.2 SHAREHOLDERS

Shareholder	Place of incorporation	Ownership
Nor Energy AS	Norway	50%
Petromal – Sole Proprietorship LLC	UAE	50.%

18.3 RELATED PARTY TRANSACTIONS

Related parties represent major shareholders, directors and key management personnel of the Group, and entities controlled, jointly controlled or significantly influenced by such parties. Pricing policies and terms of these transactions are approved by the Company's management.

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

	2017 USD'000
Cost of sales:	
Nor Energy AS	2,272
Petromal – Sole Proprietorship LLC	1,600
	3,872

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

	2017 USD'000
Due from related parties:	
Hemla Africa Holding Ltd.	5,700
Petromal – Sole Proprietorship LLC	402
Nor Energy AS	60
	6,162
Due to related parties:	
Petromal – Sole Proprietorship LLC	1,385
Nor Energy AS	1,133
	2,518

Compensation of key management personnel

The remuneration of directors and other members of key management during the year was as follows:

	2017 USD'000
Directors' remuneration	384
Key management personnel	623
Number of key management personnel	4

19. 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 (MMBOE)	2P reserves (MMBOE)	3P reserves (MMBOE)
PNGF SUD	7.01	9.96	12.06

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.

20. RISK MANAGEMENT

The Group's principal financial liabilities comprise of accounts payables 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 2017, 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 show the impact on profit or loss and shareholders' equity, where applicable. Financial instruments affected by market risk include, accounts receivables, accounts payable and accrued liabilities.

The sensitivity has been prepared for periods ending 31 December 2017 using the amounts of debt and other financial assets and liabilities held as at those reporting dates.

Credit risk

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

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

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

Liquidity risk

The Group seeks to limit its liquidity risk by ensuring financial support is available from the shareholders. The Group's term of sales require amounts to be paid within 45-60 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 31 December 2017 based on contractual undiscounted payments.

USD'000	*On demand*	*Less than 1 month*	*Between 1 and 3 months*	*Between 3 months and 1 year*	*More than 1 year*	*Total*
31 December 2017						
Trade accounts payable (note 13)	-	**4,412**	-	-	-	**4,412**
Amounts due to related parties	-	-	**2,518**	-	-	**2,518**
	-	**4,412**	**2,518**	-	-	**6,930**

The Company had USD 8.07 million in cash and bank balances as of 31 December 2017. 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 statement has been prepared under the assumption of going concern and realization 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.

Currency risk

The Company operates internationally and is exposed to risk arising from various currency exposures, primarily with respect to the Norwegian Kroner (NOK), the Euros (EUR), and the United States Dollars (USD). From a financial statements perspective, the subsidiary in Norway has a NOK functional currency and is exposed to fluctuations for presentation purposes in these financial statements. The volatility in NOK has resulted in a translation loss of USD 17 thousand as of 31 December 2017.

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 income statement and balance sheet 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 December 31, 2017 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.

USD'000	**+20%**	**-20%**
USD vs NOK		
Cash	1	(1)
Receivables	140	(140)
Payables	(507)	507
	(364)	364
USD vs EUR		
Cash	-	-
Receivables	-	-
Payables	(2)	2
	(2)	2

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 are fully funded for its committed 2018 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 Company has no 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 that in the forthcoming year.

21. FINANCIAL INSTRUMENTS

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, 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.

22. EVENTS SUBSEQUENT TO REPORTING DATE

- As of 21 of March 2018, post period end, the Company had officially changed its registered name from PetroHemla Ltd to its current name, PetroNor E&P Ltd.
- The production in PetroNor's assets has increased due to the improvements implemented by the Operator from around 15,000 bopd in 2017 to an average of approx. 20,220 bopd in 2018.
- Negotiations for entering PNGF Bis are ongoing. From the PNGF Sud contractor group, only Perenco and HEPCO have opted to enter PNGF Bis alongside SNPC.
- PetroNor has decided to proceed with a listing process on the Oslo Stock Exchange through a reverse take-over of London-based, African Petroleum LLC.

STATEMENT OF DIRECTORS' RESPONSIBILITY

Pursuant to the Norwegian Securities Trading Act section 5-5 with pertaining regulations we hereby confirm that, to the best of our knowledge, the Company's financial statements for 2017 have been prepared in accordance with IFRS, as provided for by the EU, and in accordance with the requirements for additional information provided for by the Norwegian Accounting Act. The information presented in the financial statements gives a true and fair picture of the Company's liabilities, financial position and results viewed in their entirety.

To the best of our knowledge, the Board of Directors' Report gives a true and fair picture of the development, performance and financial position of the Company, and includes a description of the principal risk and uncertainty factors facing the company.

28 March 2019
The Board of Directors
PetroNor E&P Ltd

Eyas Alhomouz	Knut Søvold	Gerhard Ludvigsen	Hawary Marshad
Chairman of the Board	CEO & Director	Director	Director

COMPANY AUDITORS

The auditor of the Company is appointed by the General Meeting.

The auditors will send a complete Management Letter/ Report to the Board – which is a summary report with comments from the auditors including suggestions of any improvements if needed.

The auditor may participate in meetings of the Board of Directors that deal with the annual accounts, where the auditor reviews any material changes in the Company's accounting principles, comments on any material estimated accounting figures and reports all material matters on which there has been disagreement between the auditor and the executive management of the Company.

The Board reports the remuneration paid to the auditor at the Annual General Meeting, including details of the fee paid for audit work and any fees paid for other specific assignments.

The Company's auditor is Ernst & Young Ltd, supported by Echas Revisjon AS for compliance with the Norwegian regulations.

AUDITOR'S REPORT

STATEMENT ON CORPORATE GOVERNANCE IN PETRONOR E&P

PetroNor E&P (“PetroNor” or the “Company”) aspires to ensure confidence in the Company and the greatest possible value creation over time through efficient decision making, clear division of roles between shareholders, management and the Board of Directors (the “Board”) as well as adequate communication.

PetroNor seeks to comply with all the requirements covered in The Norwegian Code of Practice for Corporate Governance. The latest version of the Code of 30 October 2014 is available on the website of the Norwegian Corporate Governance Board, www.nues.no. The Code is based on the “comply or explain” principle, in that companies should explain alternative approaches to any specific recommendation.

1. IMPLEMENTATION AND REPORTING ON CORPORATE GOVERNANCE

The main objective for PetroNor’s Corporate Governance is to develop a strong, sustainable and competitive company in the best interest of the shareholders, employees and society at large, within the laws and regulations of the countries where it operates. The Board of Directors and management aim for a controlled and profitable development and long-term creation of growth through well-founded governance principles and risk management.

The Board will give high priority to finding the most appropriate working procedures to achieve, inter alia, the aims covered by these Corporate Governance guidelines and principles.

2. BUSINESS

PetroNor is an independent E&P company based in Oslo and Abu Dhabi incorporated under the laws of Cyprus on 28 March 2017. The Company holds production, exploration and development assets in West Africa, namely the group of licenses of PNGF Sud offshore the Republic of Congo (Brazzaville). In addition, PetroNor has the right to enter negotiations for the terms of the neighbouring license of PNGF Bis.

PetroNor aims at becoming a full-cycle, Africa-focused company. In addition to entering PNGF Bis upon successful negotiations, it is its intention to acquire one or more proven and producing assets in Nigeria. The Company is also looking at incorporation gas to power or to LNG in its portfolio.

Vision statement

Our vision is to use our experience and competence, sourced from the Abu Dhabi and Norwegian oil and gas industries, in enhancing value in projects in Africa to the benefit of the countries we operate in and the shareholders of the Company.

3. EQUITY AND DIVIDENDS

PetroNor’s Board of Directors will ensure that the Company at all times has an equity capital at a level appropriate to its objectives, strategy and risk profile. The oil and gas E&P business is highly capital dependent, requiring PetroNor to be sufficiently capitalized. The Board needs to be proactive in order for PetroNor to be prepared for changes in the market.

Mandates granted to the Board to increase the Company’s share capital will normally be restricted to defined purposes. Mandates granted to the Board for issue of shares for different purposes will each be considered separately by the General Meeting. Mandates granted to the Board to issue new shares are normally limited in time to the following year’s Annual General Meeting. Any decision to deviate from the principle of equal treatment by waiving the pre-emption rights of existing shareholders to subscribe for shares in the event of an increase in share capital will be justified and disclosed accordingly. Such deviation will be made only in the common interest of the shareholders of the Company.

PetroNor is in a phase where investments in the Company's operations are required to enable future growth, and is therefore not in a position to distribute dividends. Payment of dividends will be considered in the future, based on the Company's capital structure and dividend capacity as well as the availability of alternative investments.

4. TREATMENT OF SHAREHOLDERS AND TRANSACTIONS WITH CLOSE ASSOCIATES

PetroNor has one class of shares representing one vote at the Annual General Meeting. The Articles of Association contain no restriction regarding the right to vote.

Up to date, PetroNor has only two shareholders and thus both shareholders are represented in all decisions at all levels.

All Board members, employees of the Company and close associates must internally clear potential transactions in the Company's shares or other financial instruments related to the Company prior to any transaction. All transactions between the Company and shareholders, shareholders' parent company, members of the Board of Directors, executive personnel or close associates of any such parties, are governed by the Code of Practice and going forward the rules of the Oslo Stock Exchange will have to apply, in addition to statutory law.

Any transactions with related parties, primary insiders or employees shall be made in accordance with PetroNor's own instructions for such matters.

Members of the Board and executive personnel and the shareholders have an obligation to notify the Board if they have any material direct or indirect interest in any transaction entered into by the Company.

5. FREELY NEGOTIABLE SHARES

The PetroNor shares are freely negotiable in conjunction with the Articles of Association and Memorandum of Incorporation.

6. GENERAL MEETINGS

PetroNor's Annual General Meeting will be held within end of June each year going forward with appropriate calling notice for the two shareholders.

PetroNor will ensure that the resolutions and supporting information distributed are sufficiently detailed and comprehensive to allow shareholders to form a view on all matters to be considered at the meeting.

Shareholders who are unable to attend in person will be given the opportunity to vote by proxy. Information on the procedure for representation at the meeting through proxy will be set out in the notice for the General Meeting.

Dividend, remuneration to the Board and the election of the auditor, will be decided at the Annual General Meeting.

7. CORPORATE ASSEMBLY AND BOARD OF DIRECTORS – COMPOSITION

The composition of the Board ensures that the Board represents the common interests of the two shareholders and meets the Company's need for expertise, capacity and diversity.

The members of the Board represent a wide range of experience including offshore, energy, banking and investment. The Chairman of the Board of Directors is elected by the General Meeting. The Company has not experienced a need for a permanent deputy Chairman.

8. THE WORK OF THE BOARD OF DIRECTORS

The Board has the overall responsibility for the management and supervision of the activities in general. The Board decides the strategy of the Company. The Board's instructions for its own work as well as for the executive management have particular emphasis on clear internal allocation of responsibilities and duties.

The Chairman of the Board ensures that the Board's duties are undertaken in efficient and correct manner. The Board shall stay informed of the Company's financial position and ensure adequate control of activities, accounts and asset management. The Board member's experience and skills are crucial to the Company both from a financial as well as an operational perspective. The Board of Directors evaluates its performance and expertise annually.

The CEO is responsible for the Company's daily operations and ensures that all necessary information is presented to the Board.

Due to the limited number of shareholders and directors in the Company has led the Board to conclude that it is currently more efficient for the Board function that all directors participate in all decisions and thus no specific subcommittees such as an Audit Committee or Remuneration Committee have been established. This practice will be further assessed in the future.

9. RISK MANAGEMENT AND INTERNAL CONTROL

Financial and internal control, as well as short and long term strategic planning and business development, all according to PetroNor's business idea and vision and applicable laws and regulations, are the Board's responsibilities and the essence of its work. This emphasizes the focus on ensuring proper financial and internal control, including risk control systems.

The Board approves the Company's strategy and level of acceptable risk. The Board carries out a continuous review of the Company's most important areas of exposure to risk and its internal control arrangements. The Directors have during the first two years of operations had informal conference calls on a weekly basis and formal meetings ad-hoc when required.

10. REMUNERATION OF THE BOARD OF DIRECTORS

As the Board of PetroNor consists of shareholders' representative, there has up to date been no remuneration for the position as a Director in PetroNor. However, there has been a remuneration for the position as a director of the subsidiary Hemla E&P Congo SA. This remuneration is approved by the Annual General Meeting in HEPCO and the remuneration is paid to the respective companies of the representing director.

The remuneration to the Board is not linked to the Company's performance. Remuneration in addition to normal director's fee will be specifically identified in the Annual Report.

11. REMUNERATION OF THE EXECUTIVE PERSONNEL

The executive personnel in the Company has up to Q4-2018 been seconded to the Company based on services agreements between the Company and the relevant shareholder. Each shareholder has charged the Company (or the Group companies) USD 50.000 per month for the services as management and directors. Going forward the Company will set out guidelines for the remuneration of the executive personnel. The guidelines will set out the main principles applied in determining the salary and other remuneration of the executive personnel. The guidelines shall ensure convergence of the financial interests of the executive personnel and the shareholders.

Going forward the Board of Directors (independent of the management) shall determine the compensation structure and remuneration level of the Company's management team.

The remuneration shall, both with respect to the chosen kind of remuneration and the amount, encourage addition of value to the Company and contribute to the Company's common interests – both for management as well as the owners.

12. INFORMATION AND COMMUNICATION

The Company is in process of formalising its guidelines for the Company's reporting of financial and other information. PetroNor shall make four quarterly presentations a year to its shareholders going forward. The Company will also make investor presentations at conferences in and out of Norway.

13. TAKEOVERS

As per March 2019 the Company has entered into a reverse take-over process with African Petroleum Corporation which is listed at Oslo Stock Exchange.

14. REPORTING OF PAYMENTS TO GOVERNMENTS

This report is prepared in accordance with the Norwegian Accounting Act § 3-3d. It states that the companies engaged in the activities within the extractive industries shall annually prepare and publish a report containing information about their payments to governments at country and project level. The Ministry of Finance has issued a regulation (F20.12.2013 nr 1682 - "the regulation") stipulating that the reporting obligation only apply to reporting entities above a certain size and to payments above certain threshold amounts. In addition, the regulation stipulates that the report shall include other information than payments to governments, and provides more detailed rules with regard to definitions, publication and group reporting.

This report contains information for the activity in the whole fiscal year 2017 for PetroNor.

The management of PetroNor has applied judgement in interpretation of the wording in the regulation with regard to the specific type of payments to be included in this report, and on what level it should be reported.

As part of the award of its participation interest in PNGF Sud, the Company has made the following payments to the Republic of Congo, in addition to the royalty and taxes paid in kind as per the PSC:

- USD 300,000 to the Ministry of Hydrocarbons as tender participation costs and access to the technical data-room;
- USD 5.88 million to the Ministry of Hydrocarbons as a farm-in fee (this is the relative portion of the USD 25 million license acquisition fee, corresponding to two tranches of USD 2.94 million as the license partners are carrying SNPC in the farm-in payment);
- USD 1.2 million as an entry ticket to the Ministry of Hydrocarbons;
- USD 1.15 million to the Ministry of Finance / Public Treasury for the Company's share of contribution for social projects of national interest.

Although PetroNor, through its subsidiary, has extractive activities and ownership interest in the PNGF Sud group of licenses, the licenses are not operated by PetroNor and as such cash calls are disbursed to operating partner and therefore none of these payments during 2017 can be construed as payments direct to governments under the regulation.

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. The Company is planning to register with the Extractive Industries Transparency Initiative, ETIT this year.

GLOSSARY AND DEFINITIONS

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

COMPANY ADDRESS

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PETRONOR E&P LTD.
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
FOR THE YEAR ENDED 31 DECEMBER 2018

	Notes	**2018**	**2017**
		$'000	*$'000*
Revenue	3	85,811	57,936
Cost of sales	4	(26,319)	(19,698)
Gross profit		**59,492**	**38,238**
Other income		491	-
General and administrative expenses	5	(9,035)	(3,428)
Operating profit		**50,948**	**34,810**
Finance costs	6	(2,623)	(878)
Foreign exchange gain / (loss)		(88)	(157)
Profit before income tax		**48,237**	**33,775**
Income tax expense	7	(31,124)	(22,621)
Profit for the year		**17,113**	**11,154**
Other comprehensive income		-	-
Total comprehensive income		**17,113**	**11,154**
Attributable to:			
Equity holders of the parent		7,864	5,850
Non-controlling interests		9,249	5,304
		17,113	**11,154**

PETRONOR E&P LTD.
CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS OF 31 DECEMBER 2018

	Notes	2018	2017
		$'000	*$'000*
ASSETS			
NON-CURRENT ASSETS			
INTANTGIBLE ASSETS			
Licenses	8	5,556	6,451
Goodwill	9	9	9
Total intangible assets		**5,565**	**6,460**
TANGIBLE ASSETS			
Production assets and equipment	10	12,580	10,854
Total tangible assets		**12,580**	**10,854**
Total non-current assets		**18,145**	**17,314**
CURRENT ASSETS			
Inventories	11	2,570	2,369
Trade and other receivables	12	28,210	7,043
Cash and cash equivalents	13	7,926	8,069
Total current assets		**38,706**	**17,481**
TOTAL ASSETS		**56,851**	**34,795**
EQUITY AND LIABILITIES			
EQUITY			
Issued Capital	14	120	120
Statutory Reserve		168	-
Retained earnings		13,591	5,850
Equity attributable to equity holders of parent		**13,879**	**5,970**
Non-controlling interest		12,795	5,713
Total equity		**26,674**	**11,683**
NON-CURRENT LIABILITIES			
Provision for decommissioning costs	15	13,496	12,672
Loan	16	7,083	-
Total non-current liabilities		**20,579**	**12,672**
CURRENT LIABILITIES			
Accounts payable and accrued liabilities	17	9,598	10,440
Total current liabilities		**9,598**	**10,440**
Total liabilities		**30,177**	**23,112**
TOTAL EQUITY AND LIABILITIES		**56,851**	**34,795**

PETRONOR E&P LTD.
CONSOLIDATED STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED 31 DECEMBER 2018

	Notes	2018	2017
		$'000	*$'000*
OPERATING ACTIVITIES			
Profit before income tax		48,237	33,775
Adjustments for:			
- Depreciation & amortization	8 & 10	3,206	2,511
- Unwinding of discount on decommissioning		824	773
		52,267	**37,059**
Working capital adjustments:			
- Inventories		(201)	(2,369)
- Trade and other receivables		(21,167)	(7,043)
- Accounts payable and accrued liabilities		(839)	10,440
		(22,207)	**1,028**
Tax paid	7	(31,124)	(22,621)
NET CASH FLOWS FROM OPERATIONS		**(1,064)**	**15,466**
INVESTING ACTIVITIES			
Acquisition of subsidiary, recognized goowill		-	(9)
Acquisition of oil and gas properties		(4,037)	(7,917)
Proceeds from slae of non-controlling interest		-	409
NET CASH USED IN INVESTING ACTIVITIES		**(4,037)**	**(7,517)**
FINANCING ACTIVITIES			
Issued capital		-	120
Dividend paid to non-controllig interest		(2,125)	
Long term loan		7,083	-
NET CASH FLOWS FROM FINANCING ACTIVITIES		**4,958**	**120**
INCREASE IN CASH & CASH EQUIVALENTS		**(143)**	**8,069**
Cash & cash equivalents, beginning of year		8,069	-
CASH & CASH EQUIVALENTS, END OF YEAR		**7,926**	**8,069**

PETRONOR E&P LTD.
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE YEAR ENDED 31 DECEMBER 2018

	Attibutable to ordinary equity holders of the Company					
	Share capital	*Retained Earnings*	*Statutory Reserve*	*Total*	*Non-controlling interests*	*Total*
Balance at 1 January 2017	-	-	-	-	-	-
Share Capital	120	-	-	120	-	120
Acquisition of a Subsidiary	-	-	-	-	409	409
Total comprehensive Income for the year	-	5,850	-	5,850	5,304	11,154
Balance at 31 December 2017	**120**	**5,850**	**-**	**5,970**	**5,713**	**11,683**
Transfer to statutory reserve	-	(168)	168	-	-	-
Increase in share capital of subsidiary	-	-	-	-	2	2
Total comprehensive Income for the year	-	7,909	-	7,909	9,205	17,114
Dividend paid	-	-	-	-	(2,125)	(2,125)
Balance at 31 December 2018	**120**	**13,591**	**168**	**13,879**	**12,795**	**26,674**

PROFIT AND LOSS

HEMLA AFRICA HOLDING AS

OPERATING INCOME AND OPERATING EXPENSES	Note	2017	2016
Revenue		612 537 864	0
Operating Income		612 537 864	0
Raw materials and consumables used		254 552 945	0
Payroll expenses		8 180 925	0
Depreciation and amortisation expense		8 230 023	0
Other operating expenses		80 337 658	9 750
Operating expenses		351 301 551	9 750
Operating profit		261 236 313	-9 750
FINANCIAL INCOME AND EXPENSES			
Other interest income		37	37
Other Interest expenses		5	0
Other financial expenses		3 813 583	0
Net financial income and expenses		-3 813 551	37
Operating result before tax		257 422 761	-9 713
Tax on ordinary result		185 131 568	0
Operating result after tax		72 291 194	-9 713
Annual net profit		72 291 194	-9 713
Minority share		18 091 436	0
Majority share		54 199 758	-9 713
Total allocated		72 291 194	-9 713

BALANCE SHEET

HEMLA AFRICA HOLDING AS

ASSETS	Note	2017	2016
FIXED ASSETS			
INTANGIBLE FIXED ASSETS			
Concessions, patents, licences, trademarks, and similar rights		52 799 620	0
Total intangible assets		52 799 620	0
TANGIBLE FIXED ASSETS			
Machinery		3 690 623	0
Total tangible fixed assets		3 690 623	0
FINANCIAL FIXED ASSETS			
Total fixed assets		56 490 243	0
CURRENT ASSETS			
Inventories		28 281 525	0
DEBTORS			
Accounts receivables		5 724 648	0
Other receivables		50 819 345	0
Total debtors		56 543 993	0
INVESTMENTS			
Cash and bank deposits		66 039 757	37 110
Total current assets		150 865 275	37 110
Total assets		207 355 518	37 110

BALANCE SHEET

HEMLA AFRICA HOLDING AS

EQUITY AND LIABILITIES	Note	2017	2016
RESTRICTED EQUITY			
Share capital		30 000	30 000
Share premium reserve		-14 500	-14 500
Total restricted equity		15 500	15 500
RETAINED EARNINGS			
Other equity		54 106 353	-93 405
Total retained earnings		54 106 353	-93 405
Minority interest		21 365 116	0
Total equity		75 486 969	-77 905
LIABILITIES			
PROVISIONS			
OTHER LONG-TERM LIABILITIES			
CURRENT LIABILITIES			
Trade creditors		101 830 040	0
Public duties payable		27 813 529	0
Other short term liabilities		2 224 980	115 015
Total short term liabilities		131 868 549	115 015
Total liabilities		131 868 549	115 015
Total equity and liabilities		207 355 518	37 110

Oslo, 29.06.2018
The board of Hemla Africa Holding AS

Knut Søvold	Gerhard Ludvigsen	Eyas A Alhomouz
chairman of the board	member of the board	member of the board

INDIRECT CASH FLOW

HEMLA AFRICA HOLDING AS

Statement of cash flows (NRS - Indirect model)
NRS Indirect method

		Note	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES				
	Profit/loss before tax		257 422 761	-9 713
-	Tax paid for the period		-185 131 568	0
+	Ordinary depreciation		8 230 023	0
+/-	Change in inventory		-28 281 525	0
+/-	Change in accounts receivable		-5 724 648	0
+/-	Change in accounts payable		101 830 040	0
+/-	Change in other accrual items		-20 895 851	115 015
=	Net cash flows from operating activities		127 449 233	105 302
CASH FLOWS FROM INVESTMENT ACTIVITIES				
-	Payments for the purchase of fixed assets		64 720 266	0
=	Net cash flows from investment activities		-64 720 266	0
CASH FLOWS FROM FINANCING ACTIVITIES				
+	Proceeds from equity minority interest		3 273 680	0
=	Net cash flows from financing activities		3 273 680	0
=	Net change in cash and cash equivalents		66 002 647	105 302
+	Cash and cash equivalents at the start of the period		37 110	0
=	Cash and cash equivalents at the end of the period		66 039 757	105 302

Hemla Africa Holding AS

Notes to Group's consolidated Annual Accounts 2017

Note 1 Accounting Principles

The financial statements have been prepared in accordance with the Norwegian Accounting Act and generally accepted accounting principles in Norway.

Basis for consolidation

The Group's consolidated financial statements comprise Hemla Africa Holding AS and companies in which Hemla Africa Holding AS has a controlling interest. A controlling interest is normally obtained when the Group owns more than 50% of the shares in the company and can exercise control over the company. Minority interests are included in the Group's equity. Transactions between group companies have been eliminated in the consolidated financial statement. The consolidated financial statement has been prepared in accordance with the same accounting principles for both parent and subsidiary.

The purchase method is applied when accounting for business combinations. Companies which have been bought or sold during the year are included in the consolidated financial statements from the date when control is achieved and until the date when control ceases.

An associate is an entity in which the Group has a significant influence but does not exercise control the management of its finances and operations (normally when the Group owns 20%-50% of the company). The consolidated financial statements include the Group's share of the profits/losses from associates, accounted for using the equity method, from the date when a significant influence is achieved and until the date when such influence ceases.

When the Group's share of a loss exceeds the Group's investment in an associate, the amount carried in the Group's balance sheet is reduced to zero and further losses are not recognised unless the Group has an obligation to cover any such loss.

Use of estimates

The management has used estimates and assumptions that have affected assets, liabilities, incomes, expenses and information on potential liabilities in accordance with generally accepted accounting principles in Norway

Foreign currency translation

Transactions in foreign currency are translated at the rate applicable on the transaction date. Monetary items in a foreign currency are translated into NOK using the exchange rate applicable on the balance sheet date. Non-monetary items that are measured at their historical price expressed in a foreign currency are translated into NOK using the exchange rate applicable on the transaction date. Non-monetary items that are measured at their fair value expressed in a foreign currency are translated at the exchange rate applicable on the balance sheet date. Changes to exchange rates are recognised in the income statement as they occur during the accounting period.

Hemla Africa Holding AS

Notes to Group’s consolidated Annual Accounts 2017

Revenue recognition

Revenues from the sale of goods are recognised in the income statement once delivery has taken place and most of the risk and return has been transferred.

Revenues from the sale of services and long-term manufacturing projects are recognised in the income statement according to the project’s level of completion provided the outcome of the transaction can be estimated reliably. Progress is measured as the number of hours spent compared to the total number of hours estimated. When the outcome of the transaction cannot be estimated reliably, only revenues equal to the project costs that have been incurred will be recognised as revenue. The total estimated loss on a contract will be recognised in the income statement during the period when it is identified that a project will generate a loss.

Income tax

The tax expense consists of the tax payable and changes to deferred tax. Deferred tax/tax assets are calculated on all differences between the book value and tax value of assets and liabilities. Deferred tax is calculated as 23% percent of temporary differences and the tax effect of tax losses carried forward.. Deferred tax assets are recorded in the balance sheet when it is more likely than not that the tax assets will be utilized. Taxes payable and deferred taxes are recognised directly in equity to the extent that they relate to equity transactions.

Balance sheet classification

Current assets and short term liabilities consist of receivables and payables due within one year, and items related to the inventory cycle. Other balance sheet items are classified as fixed assets / long term liabilities.

Current assets are valued at the lower of cost and fair value. Short term liabilities are recognized at nominal value.

Fixed assets are valued at cost, less depreciation and impairment losses. Long term liabilities are recognized at nominal value.

Research and development

Development costs are capitalized providing that a future economic benefit associated with development of the intangible asset can be established and costs can be measured reliably. Otherwise, the costs are expensed as incurred. Capitalized development costs is amortized linearly over its useful life. Research costs are expensed as incurred.

Property, plant and equipment

Property, plant and equipment is capitalized and depreciated linearly over the estimated useful life. Significant fixed assets which consist of substantial components with dissimilar economic life have been unbundled; depreciation of each component is based on the economic life of the component. Costs for maintenance are expensed as incurred, whereas costs for improving and upgrading property plant and equipment are added to the acquisition cost and depreciated with the related asset. If carrying value of a non-current asset exceeds the estimated recoverable amount, the asset is written down to the recoverable amount. The recoverable amount is the greater of the net realisable value and value in use. In assessing value in use, the discounted estimated future cash flows from the asset are discounted are used.

Subsidiaries and investment in associates

Subsidiaries and investments in associates are valued at cost in the company accounts. The investment is valued as cost of the shares in the subsidiary, less any impairment losses An impairment loss is recognised if the impairment is not considered temporary, in accordance with generally accepted accounting principles. Impairment losses are reversed if the reason for the impairment loss disappears in a lather period.

Dividends, group contributions and other distributions from subsidiaries are recognised in the same year as they are recognised in the financial statement of the provider. If dividends / group contribution exceed withheld profits after the acquisition date, the excess amount represents repayment of invested capital, and the distribution will be deducted from the recorded value of the acquisition in the balance sheet for the parent company.

Inventories

Inventories are recognised at the lowest of cost and net selling price. The net selling price is the estimated selling price in the case of ordinary operations minus the estimated completion, marketing and distribution costs. The cost is arrived at using the FIFO method and includes the costs incurred in acquiring the goods and the costs of bringing the goods to their current state and location.

Accounts receivable and other receivables

Accounts receivable and other current receivables are recorded in the balance sheet at nominal value less provisions for doubtful accounts. Provisions for doubtful accounts are based on an individual assessment of the different receivables. For the remaining receivables, a general provision is estimated based on expected loss.

Short term investments

Short term investments (stocks and shares seen as current assets) are valued at the lower of acquisition cost and fair value at the balance sheet date. Dividends and other distributions are recognized as other financial income.

Pensions

Defined benefit plans are valued at the present value of accrued future pension benefits at the balance sheet date. Pension plan assets are valued at their fair value.

Changes in the pension obligations due to changes in pension plans are recognised over the estimated average remaining service period. The accumulated effect of changes in estimates and in financial and actuarial assumptions (actuarial gains or losses) that is less than 10% of the higher of defined benefit pension obligations and pension plan assets at the beginning of the year is not recognised. When the accumulated effect is above 10% limit in the beginning of the financial period, the excess amount is recognised in the income statement over the estimated average remaining service period. The net pension cost for the period is classified as salaries and personnel costs.

Hemla Africa Holding AS

Notes to Group's consolidated Annual Accounts 2017

Cash flow statement

The cash flow statement is presented using the indirect method. Cash and cash equivalents includes cash, bank deposits and other short term, highly liquid investments with maturities of three months or less.

Note 1 Salary and personnel costs, number of employees, loans to employees and auditor's fee

No salary or remuneration has been paid to the general manager or board of directors of the year. The company has no employees and is therefore not obliged to have a statutory OTP agreement.

The cost of auditing fees for 2017 amounts to NOK 24,319.
In addition, fees for technical accounting assistance amount to NOK 0.

Note 2 Share capital and shareholder information

The company's share capital of NOK 30,000 consists of 30,000 shares with a nominal value of NOK 1.

The company's shareholders are	Ownership
Nor Energy AS	66,67 %
Petromal Owned by National Holding	33,33 %

Note 3 Equity

	Share-capital	Other equity	Other equity	Minority interest	Total
Pr. 1.1	30 000	-14 500	-93 405	0	-77 905
Minoritys part of sharecapital in Hemla E&P				3 273 680	3 273 680
Profit for the year			54 199 758	18 091 436	72 291 194
Pr. 31.12	30 000	-14 500	54 106 353	21 365 116	75 486 969

Note 4 Income Taxes

The tax expense for the year consists of:

	2017
Tax payable	185 131 568
Changes in deferred tax	0
Total income tax expense	185 131 568

Note 5 Transactions and balances with related parties

Overview of related parties

Related party	Affiliation	Ownership
NOR Energy AS	Shareholder	66,67 %
Petromal Owned by National Holding	Shareholder	33,33 %

The group has conducted several different transactions with related parties. All transactions are carried out as part of the ordinary business and at arm's prices. The most important transactions that are made are as follows:

a) Purchase of services and coverage of costs from NOR Energy AS	NOK	14 048 218
a) Purchase of services and coverage of costs from Petromal	NOK	8 591 118

The balance sheet includes the following amounts as a result of transactions with related parties:

	NOR Energy AS	Petromal	Total
Accounts payable	9 261 446	11 334 026	20 595 472
Total	9 261 446	11 334 026	20 595 472

Note 6 Fixed assets

	Patents, Licenses & approvals	Macinery	Total
Cost value 1.1.	0	0	0
+ Additions	60 415 764	4 304 502	64 720 266
- Disposions	0	0	0
- Accumulated depreciations	-7 616 145	-613 878	-8 230 023
= Net book value 31.12	52 799 620	3 690 623	56 490 243
Depreciations this year	-7 616 145	-613 878	-8 230 023

ECHAS REVISJON AS

STATSAUTORISERT REVISOR
ERIK CHRISTOFFERSEN

SLEPENDVEIEN 48
1341 SLEPENDEN
TLF.: 67 80 90 80
ORG.NR.: 980 906 965
E-POST: ERIK.CHRISTOFFERSEN@ECHAS.NO

To the Shareholders' Meeting of Hemla Africa Holding AS

Independent auditor`s report

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of Hemla Africa Holding AS (the Company), showing a loss of NOK 74 553 in the financial statements of the parent company and a profit of NOK 72 291 194 in the financial statements of the group, in our opinion:

- The financial statements are prepared in accordance with laws and regulations
- The accompanying financial statements give a true and fair view of the financial position of the parent company as at December 31, 2017, and (of) its financial performance and its cash flows for the year then ended in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway.
- The accompanying financial statements give a true and fair view of the financial position of the group as at December 31, 2017, and (of) its financial performance and its cash flows for the year then ended in accordance with Norwegian Accounting Act and accounting standards and practices generally accepted in Norway.

The financial statements comprise:

- The financial statements of the parent company, which comprise the balance sheet as at December 31, 2017, and the income statement and cash flow statement for the year then ended, and notes to the financial statements, including a summary of significant accounting policies, and
- The financial statements of the group, which comprise the balance sheet as at December 31, 2017, and the income statement and cash flow statement for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

Basis for Opinion

We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, included International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Company as required by laws and regulations, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion

Other Information

Management is responsible for the other information. The other information comprises the information included in the X report, but does not include the financial statements and our auditor's report thereon.

Our opinion on the financial statements 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 statements, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements 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 Board of Directors and the Managing Director for the Financial Statements
The Board of Directors and the Managing Director (Management) are responsible for the preparation and fair presentation of the financial statements in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Groups's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends 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 Statements
Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are 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 ISAs 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 these financial statements.

Refer to https://revisorforeningen.no/revisjonsberetninger which contains a description of Auditor's responsibilities.

Report on Other Legal and Regulatory Requirements

Opinion on the Board of Directors' report
Based on our audit of the financial statements as described above, it is our opinion that the information presented in the Board of Directors' report concerning the financial statements and the going concern assumption is consistent with the financial statements and complies with the law and regulations.

Opinion on Registration and Documentation
Based on our audit of the financial statements as described above, and control procedures we have considered necessary in accordance with the International Standard on Assurance Engagements (ISAE) 3000, «Assurance Engagements Other than Audits or Reviews of Historical Financial Information», it is our opinion that management has fulfilled its duty to produce a proper and clearly set out registration and documentation of the Company's accounting information in accordance with the law and bookkeeping standards and practices generally accepted in Norway.

Slependen,29.06.2018
Echas Revisjon AS
Erik Christoffersen
Erik Chrisoffersen
State Authorized Public Accountant

Dép 38201800 5333 du 20/07/18-

UNITE DES ... ENTREPRISES
DE ... (PNR)
S... ...RIAT
Arrivée le: 20 JUIL 2018
Enrég.sous le N°

27 JUIL 2018
DIRECTION DEPARTEMENTALE DU KOUILOU

HEMLA EP CONGO SA

27 Avenue Amilcar CABRAL, Côte Mondaine
BP 2722
POINTE NOIRE

BILAN AU 31 décembre 2017

Reçu le 27 juillet 2018

ENREGISTREMENT DES DOMAINES ET TIMBRE
BUREAU DE POINTE-NOIRE
REPUBLIQUE DU CONGO

HEMLA EP CONGO SA

27 Avenue Amilcar CABRAL, Côte Mondaine
BP 2722
POINTE NOIRE

BILAN AU 31 décembre 2017

COMMUNAUTE ECONOMIQUE ET MONÉTAIRE
DE L'AFRIQUE CENTRALE
(CEMAC)

=-=-=-=-=-==-

REPUBLIQUE DU CONGO
Francs CFA

=-=-=-=-=-==-

DECLARATION STATISTIQUE ET FISCALE
- ETATS FINANCIERS -

Exercice clos le : ***31 décembre 2017***

Désignation de l'entreprise

Raison sociale (dénomination) : (ou nom et prénom de l'exploitant)	**HEMLA EXPLORATION AND PRODUCTION CONGO**
Sigle :	**HEMLA EP CONGO**
Forme juridique :	**Société Anonyme**
Régime fiscal :	**Réel**
Agréments obtenus :	Date :
Pays du siège social : Congo	**République du Congo**
Adresse complète :	**27 Avenue Amilcar CABRAL, Côte Mondaine, BP 2722 Centre-Ville Pointe-Noire**
Numéro d'identification unique (NIU) :	**M2017110000335120**
Date de création de l'entreprise :	**29-déc-16**

Système comptable NORMAL

CACHET DE L'ENTREPRISE

Retour obligatoire avant le 20 mai

FICHE D'IDENTIFICATION ET RENSEIGNEMENTS DIVERS

Désignation de l'entreprise : *HELMA EXPLORATION AND PRODUCTION CONGO* Sigle usuel : *HEMLA EP CONGO*
Adresse géographique : *27 Avenue Amilcar CABRAL, Côte Mondaine, BP 2722 Centre-Ville Pointe-Noire*
N.I.U. : *M2017110000335120* Exercice clos le : *31/12/2017* Durée (en mois) *12*

ZA			HEPC@HEMLAAFRICA.COM	242	2722	Pointe-Noire
	N° de téléphone	N° de télécopie	E-mail	Code Pays	B.P.	Ville

ZB EXERCICE COMPTABLE DU 29/12/2016 AU 31/12/2017

ZC *CG PNR 16 B 1414*
N° Registre du Commerce et du Crédit mobilier

ZD 12016073/68
N° Sécurité sociale

ZE Recherche, Production, Transport, Commercialisation des Hydrocarbures
Désignation précise de l'activité exercée par l'entreprise — Code

ZF TCHIBOTA GOMA Valentin, Immeuble Tangu Center Face Lycée POATY Bernard 2e étage Pointe-Noire, Directeur Général Adjoint
Nom, adresse et qualité de la personne à contacter en cas de demande d'information complémentaires

ZG NGOMA MBOUKOU Wilfrid
Nom du responsable comptable de l'entreprise

ZH
Nom du cabinet comptable

ZI
Adresse du cabinet comptable

ZJ TCHIBOTA GOMA Valentin
Nom et qualité du signataire des états financiers

Date de signature **01/03/2017**

Signature

				Contrôle de l'entreprise (cocher la case)	
ZK	Nombre d'établissement dans le pays :	1	ZN	Entreprise sous contrôle public	
ZL	Nombre d'établissement hors du pays pour lesquels une comptabilité distincte est tenue:	0	ZO	Entreprise sous contrôle privé national	
ZM	Première anneé d'exercice dans le pays:	2017	ZP	Entreprise sous contrôle privé étranger	

ACTIVITES DE L'ENTREPRISE

Désignation de l'activité (¹)	Code nomenclature d'activité (¹)	Chiffre d'affaires HT (CAHT)	% activité dans le CAHT
Recherche, Production, Transport, Commercialisation des Hydrocarbures		**68 351 206,32**	**100%**
Autres			
	Total	**68 351 206,32**	**100%**

Désignation de l'entreprise : *HEMLA EXPLORATION AND PRODUCTION CONGO* Sigle usuel : *HEMLA EP CONGO*
Adresse géographique : *27 Avenue Amilcar CABRAL, Côte Mondaine, BP 2722 Centre-Ville, Pointe-Noire*
N.I.U. : **M2017110000335120** Exercice clos le : *31/12/2017* Durée (en mois) *12*

DIRIGEANTS(1)

Nom et Prénoms		Age	Sexe	Nationalité	Qualité
ALHOMOUZ RANDA	Eyas A.A.	40	Masculin	Américaine	DG
TCHIBOTA GOMA	Valentin	62	Masculin	Congolaise	DGA

(1) Dirigeant = Président, Directeur Général, Administrateur Général, Gérant, Autres

ACTIONNAIRES OU ASSOCIES PRINCIPAUX (par ordre décroissant du capital souscrit)

Nom et Prénoms		Nationalité	Capital Montant (en USD)	Capital %
HELMA AFRICA HOLDING		Norvégienne	1 152 000,00	72,00%
MGI		Congolaise	396 000,00	24,75%
ALOMHOUZ	Eyas	Américaine	36 000,00	2,25%
KOSTEVEIT	Trond	Norvégienne	12 000,00	0,75%
NTSIBA	Patrick Robert	Congolaise	4 000,00	0,25%
			-	
			-	
			-	
			1 600 000,00	100,00%

MEMBRES DU CONSEIL D'ADMINISTRATION

Nom et Prénoms		Age	Sexe	Nationalité	Qualité
ALHOMOUZ	Eyas		Masculin	Américaine	Président
SOVOLD	Knut		Masculin	Norvégienne	Administrateur
KOSTVEIT	Trond		Masculin	Norvégienne	Administrateur
NGOMA BIKOUNGOU	Léon		Masculin	Congolsaise	Administrateur
NTSIBA	Patrick Robert		Masculin	Congolsaise	Administrateur

FILIALES ET PARTICIPATIONS

Désignation		Nationalité		Capital Montant (en F CFA)	Capital %
			Total		

MOUVEMENT DU PERSONNEL

	Effectifs en début d'exercice	Variation de l'exercice Entrées (1)	Variation de l'exercice Sorties (2)	Effectifs en fin d'exercice
- Cadres supérieurs		4		4
- Techniciens supérieurs et Cadres moyens		1		1
- Techniciens, agents de maîtrise et ouvriers qualifiés		3		3
- Employés, manoeuvres, ouvriers et apprentis				-
TOTAL	-	8	-	8

(I) Nouvelles embauches ou personnel de l'entreprise non compté en début d'exercice
(2) Licenciés ou affectés en dehors de l'entreprise au cours de l'exercice

LISTE DES ETABLISSEMENTS DE L'ENTREPRISE EN FIN D'EXERCICE

Nom et adresse de l'Etablissement				Activité principale de l'Etablissement	Date de création ou d'acquisition	SI acquisition nom de l'ancien propriétaire	Effectifs permanents en fin d'exercice
Nom	Localité	B..P	Tél.				
1.							
2							

Définition

* *Entreprise* : On appelle entreprise, toute personne physique ou morale exerçant de façon autonome une activité professionnelle non salariée.

* *Etablissement:* On appelle établissement$_s$ tout lieu possédant un caractère topographique distinct, où s'exerce l'activité dune entreprise. Cette définition est complétée par les critères suivants :

a)- de permanence : la durée normale d'exercice de l'activité de l'entreprise en un lieu donné doit être au maximum de six mois pour que l'on considère qu'il soit établissement ;

b)- de lieu : les locaux d'une entreprise située dans une même enceinte d'un seul tenant ne constituent qu'un seul établissement.

STRUCTURE DE L'ACTIVITE PAR ETABLISSEMENT

OPERATION \ ETABLISSEMENT		Etablissement N1 (2)	Etablissement N2 (2)	Etablissement N3 (2)	Etablissement N4 (2)	TOTAL
Venta rnarch.(1)	A)-Activités Commerc.					
	Total Compte 701					
Produits vendus (1)	B)-Activités de prod. de biens					
	Total Prod. Biens Cpte 702					
Serv. vendus et trav. facturés (1)	C)-Activités de prest. de services					
	Total Serv. vendus et trav. facturés, Cpte 706					
TOTAL (A + B + C)						
D)- Cessions entre						
Salaires versés						
Effectifs salariés						
Personnel saisonnier *(Nombre de journée de travail)*						
Investissements réalisés						

(I) A ventiler par nature toutes taxes comprises

(2) Joindre un état annexe si le cadre ne suffit pas

N.B. Pour les établissements, suivre l'ordre indiqué dans le ste des établissements)

A - BILAN - SYSTEME NORMAL

Désignation de l'entreprise : HEMLA EXPLORATION AND PRODUCTION CONGO
Adresse : Avenue Général de Gaulle, Immeuble Losange, Centre-Ville Pointe-Noire
Numéro d'identification *M2017110000335120* Exercice clos le *31 décembre 2017* Durée en mois *12*

Réf	Actif	Exercice N brut	Exercice N Amort./Prov.	Exercice N Net	Ex. N-1 Net
	ACTIF IMMOBILISE (1)				
AA	**Charges immobilisées**				
AX	Frais d'établissement				
AY	Charges à répartir				
	Primes de remboursement des obligations				
AD	**Immobilisations incorporelles**				
AE	Frais de recherches et développement				
AF	Brevetes, licences, logiciels	7 382 000	930 591	6 451 409	
AG	Fonds commercial				
AH	Autres immobilisations incorporelles				
AI	**Immobilisations corporelles**				
AJ	Terrains				
AK	Bâtiments				
AL	Installations et agencements	525 953	66 303	459 650	
AM	Matériel				
AN	Matériel de transport	8 705	8 705	0	
AP	Avances et acomptes versés sur immobilisations				
AQ	**Immobilisations financières**				
AR	Titres de participation				
AS	Autres immobilisations financières	31 192		31 192	
AW	(I) dont H.A.O. : Brut / Net /				
AZ	**TOTAL ACTIF IMMOBILISE (I)**	**7 947 850**	**1 005 599**	**6 942 251**	**0,00**

A - BILAN - SYSTEME NORMAL

Désignation de l'entreprise : HEMLA EXPLORATION AND PRODUCTION CONGO
Adresse : Avenue Général de Gaulle, Immeuble Losange, Centre-Ville Pointe-Noire
Numéro d'identification : *M2017110000335120* Exercice clos le *31 décembre 2017* Durée en mois *12*

Réf	Actif	Exercice N brut	Exercice N Amort./Prov.	Exercice N Net	Ex. N-1 Net
AZ	Report Total Actif Immobilisé	7 947 850	1 005 599	6 942 251	
	ACTIF CIRCULANT				
BA	Actif circulant H.A.O.				
BB	**Stocks**				
BC	Marchandises				
BD	Matières premières et autres approvisionnements	512 818		512 818	
BE	En cours				
BF	Produits fabriqués	2 934 101		2 934 101	
BG	**Créances et emplois assimilés**				
BH	Fournisseurs avances versées			0	
BI	Clients	3 418 800		3 418 800	
BJ	Autres créances	6 247 027		6 247 027	
BK	**TOTAL ACTIF CIRCULANT (II)**	**13 112 747**	**0**	**13 112 747**	**0,00**
	TRESORERIE - ACTIF				
BQ	Titres de placement			0	
BR	Valeurs à encaisser			0	
BS	Banques, chèques postaux, caisse	5 837 107		5 837 107	
BK	**TOTAL TRESORERIE ACTIF (III)**	**5 837 107**	**0**	**5 837 107**	**0,00**
BU	Ecarts de conversion - Actif (IV) (perte probable de change)	37 981		37 981	
BZ	**TOTAL GENERAL (I+II+III+IV)**	**26 935 684**	**1 005 599**	**25 930 085**	**0,00**

A - BILAN - SYSTEME NORMAL

Désignation de l'entreprise : HEMLA EXPLORATION AND PRODUCTION CONGO

Adresse : Avenue Général de Gaulle, Immeuble Losange, Centre-Ville Pointe-Noire

Numéro d'identification : *M2017110000335120* Exercice clos le *31 décembre 2017* Durée en mois : *12*

Réf	PASSIF (Avant répartition)	EXERCICE N	EXERCICE N-1
	CAPITAUX PROPRES ET RESSOURCES ASSIMILEES		
CA	Capital	1 600 000	
CB	Actionnaires capital non appelé		
CC	Primes et réserves		
CD	Primes d'apport, d'émission, de fusions		
CE	Ecarts de réévaluation		
CF	Réserves indisponibles		
CG	Réserves libres		
CH	Report à Nouveau = ou -		
CI	Résultat net de l'exercice (Bénéfice + ou perte -)	8 842 128	
CK	Autres capitaux propres		
CL	Subventions d'investissements		
CM	Provisions réglementées et fonds assimilés		
BK	**TOTAL CAPITAUX PROPRES (I)**	**10 442 128**	**0,00**
	DETTES FINANCIERES ET RESSOURCES ASSIMILEES (I)		
DA	Emprunts		
DB	Dettes de crédit bail et contrats assimilés		
DC	Dettes financières diverses		
DD	Provisions financières pour risques et charges		
DE	(I) dont H.A.O.: /		
DF	**TOTAL DETTES FINANCIERES (II)**	**0**	
DG	**TOTAL RESSOURCES STABLES (I+II)**	**10 442 128**	**0,00**

A - BILAN - SYSTEME NORMAL

Désignation de l'entreprise : HEMLA EXPLORATION AND PRODUCTION CONGO
Adresse : Avenue Général de Gaulle, Immeuble Losange, Centre-Ville Pointe-Noire
Numéro d'identification *M2017110000335120* Durée en mois : *12*

Réf	PASSIF (Avant répartition)	EXERCICE N	EXERCICE N-1
	Report total Ressources stables	10 442 128	0
	PASSIF CIRCULANT		
DH	Dettes circulantes H.A.O. et ressources assimilées		
DI	Clients, avances reçues		
DJ	Fournisseurs d'exploitation	11 817 652	
DK	Dettes fiscales	3 391 160	
DL	Dettes sociales	63 637	
DM	Autres dettes		
DN	Risques provisionnés	37 981	
DP	**TOTAL PASSIF CIRCULANT (III)**	**15 310 430**	**0**
	TRESORERIE PASSIF		
DQ	Banques, crédit d'escompte		
DR	Banques, crédit de trésorerie		
DS	Banques, découverts		
DT	**TOTAL TRESORERIE PASSIF (IV)**	**0**	
DU	Ecarts de conversion - Passif (V) (gain probable de change)	177 527	
DZ	**TOTAL GENERAL (I + II + III + IV + V)**	**25 930 085**	**0**

B - COMPTE DE RESULTAT - SYSTEME NORMAL

Réf	CHARGES (1ère partie)	Exercice N	Exercice N-1
	ACTIVITE D'EXPLOITATION		
RA	Achats de marchandises		
RB	- Variation de stocks (- ou +)		
	(Marge brute sur marchandises voir TB*)*		
RC	Achats de matières premières et fournitures liées		
RD	- Variation de stocks (- ou +)		
	(Marge brute sur marchandises voir TG*)*		
RE	Autres achats	14 972 779	
RH	- Variation de stocks (- ou +)	-512 818	
RI	Transports	125 515	
RJ	Services extérieurs	5 547 382	
RK	Impôts et taxes	11 199 897	
RL	Autres charges	483 144	
	(Valeur ajoutée voir TN*)*		
RP	Charges de personnel[1]	1 062 486	
	(1) dont personnel extérieur 118 664		
RQ	*(Excédent brut d'exploitation voir* TQ*)*		
RS	Dotations aux amortissements et aux provisions	1 005 599	
RW	**Total des charges d'exploitation**	**33 883 984**	**0**
	(Résultat d'exploitation voir TX*)*		

B - COMPTE DE RESULTAT - SYSTEME NORMAL

Réf	CHARGES (2ème partie)	Exercice N	Exercice N-1
RW	Report total des charges d'exploitation	33 883 984	-
	ACTIVITE FINANCIERE		
SA	Frais financiers	104 516	
SC	Pertes de change	317 108	
SD	Dotations aux amortissements et aux provisions		
SF	**Total des charges financières**	**421 624**	**-**
	(*Résultat finanvier, voir* UG)		
SH	**Total des charges des activités ordinaires**	**34 305 608**	**-**
	(*Résultat des activités ordinaires voir* UI)		
	HORS ACTIVITES ORDINAIRES (H.A.O.)		
SK	Valeurs comptables des cessions d'immobilisations		
SL	Charges H.A.O.	5 516 965	
SM	Dotations H.A.O.		
SO	**Total des charges H.A.O.**	**5 516 965**	**-**
	(*Résultat H.A.O.voir* UP)		
SQ	Participation des travailleurs		
SR	Impôts sur le résultat	22 620 606	
SS	**Total participation et impôts**	**22 620 606**	**-**
ST	**TOTAL GENERAL DES CHARGES**	**62 443 179**	**-**
	(*Résultat net voir* UZ)		

B - COMPTE DE RESULTAT - SYSTEME NORMAL

Réf	PRODUITS (1ère partie)			Exercice N	Exercice N-1
	ACTIVITE D'EXPLOITATION				
TA	Ventes de Marchandises				
TB	**MARGE BRUTE SUR MARCHANDISES**	0	0		
TC	Ventes de produits fabriqués			68 351 206	
TD	Travaux, services vendus				
TE	Production stockée (ou déstockage) (- ou +)			2 934 101	
TF	Production immobilisée				
TG	**MARGE BRUTE SUR MATIERES**	71 285 308	-		
TH	Produits accessoires				
TI	CHIFFRES D'AFFAIRES[1] (TA+TC+TD+TH)	68 351 206	0		
TJ	(1) dont à l'exportation				
TK	Subventions d'exploitation				
TL	Autres produits				
TN	**VALEUR AJOUTEE**	39 469 408	0		
TQ	**EXCEDENT BRUT D'EXPLOITATION**	38 406 922	0		
TS	Reprises de provisions				
TT	Transferts de charges				
TW	**Total des produits d'exploitation**			71 285 308	0
TX	**RESULTAT D'EXPLOITATION** Bénéfice (+) ; Perte (-)	37 401 323	0		

B - COMPTE DE RESULTAT - SYSTEME NORMAL

Réf	PRODUITS (2ème partie)			Exercice N	Exercice N-1
TW	Report total des produits d'exploitation			71 285 308	0
	ACTIVITE FINANCIERE				
UA	Revenus financiers				
UC	Gains de change				
UD	Reprise de provisions				
UE	Transfert de charges				
UF	**Total des produits financiers**			**0**	**0**
UG	RESULTAT FINANCIER (+ ou -)	-421 624	0		
UH	**Total des produits des activités ordinaires**			**71 285 308**	**0**
UI	RESULTAT DES ACTIVITES ORDINAIRES (1) (+ ou -)	36 979 700	0		
UJ	(1) dont impôt correspondant	/			
	HORS ACTIVITES ORDINAIRES (H.A.O.)				
UK	Produits des cessions d'immobilisations				
UL	Produits H.A.O.				
UM	Reprises H.A.O.				
UN	Transferts de charges				
UO	**Total des produits H.A.O.**			**0**	**0**
UP	RESULTAT H.A.O. (+ ou -)	- 5 516 965	0		
UT	**TOTAL GEENRAL DES PRODUITS**			**71 285 308**	**0**
UZ	**RESULTAT NET**	**8 842 128**	**0**		

: DETERMINATION DU RESULTAT FISCAL
Désignation de l'entreprise *HEMLA EP CONGO*
Exercice clos le *31 décembre 2017*

	PERTE	BENEFICE
I - RESULTAT NET COMPTABLE DE L'EXERCICE		*31 462 734,77*
II -REINTEGRATION DES CHARGES OU PERTE NON DEDUCTIBLES OU PARTIELLEMENT DEDUCTIBLES AU POINT DE VUE FISCAL		
1. Taxe spéciale sur les sociétés		
2. Amortissement réputés différés au point de vue fiscal		
3. Solde IS		
4. Cadeaux Clientèle		
5. Transport congès		
6. Intérêts excédentaires des comptes courants d'associés		
7. Impôts non déductibles : RAS		
8. Amendes et pénalités non déductibles, contravention		
9. Dons et libéralités excessifs		
10. Charges n'icombant pas à l'exercice		
11. TVTS / IRVM		
12. Assurances Hors CEMAC		
13. Frais écolage		
14. Réception / Frais de représentation		
15. Provisions congés payés N		
16. Divers : logement excédentaire		
TOTAL DES REINTEGRATIONS		*31 462 734,77*
III - DEDUCTIONS DE CHARGES OU PERTES, PRODUITS OU PROFITS FISCALEMENT DEDUCTIBLES		
1. Amortissement antérieurement différés et imputés sur l'exercice		
2. Déficit reportable antérieur		
3. Provisions Congés Payés N-1		
4. 15% des caisses de retraites hors CEMAC		
5. Réinvestissement de bénéfices : quote-part déductibles		
6. Divers		
TOTAL DES DEDUCTIONS	*0*	
IV - RESULTAT NET FISCAL DE L'EXERCICE		*31 462 734,77*

V - REPORT DEFICITAIRES

EXERCICE	**2016**	**2015**	**2014**
DEFICITS REPORTES	0	0	
Déficit fiscal de l'exercice		0	0
Imputation sur le résultat fiscal	**0**	**0**	**0**
DEFICITS REPORTABLES		0	0

IMPÔT SOCIETE
LIQUIDATION DE L'IMPOT

VI - AMORTISSEMENTS REPUTES DIFFERES

EXERCICE	**2016**	**2015**	**2014**	**2013**	**2012**	**2011**	**2010**
AMORTISSEMENTS REPORTES	0	0	0	0	0	0	0
A.R.D. de l'exercice		0	0	0	0	0	0
Imputation sur le résultat fiscal	**0**	**0**	**0**	**0**	**0**	**0**	**0**
AMORTISSEMENTS REPORTABLES		0	0	0	0	0	0

VARIATION DU BESOIN DE FINANCEMENT D'EXPLOITATION (B.F.E.)

Var. B.F.E. = Var. Stocks[2] + Var. Créances[2] + Var. Dettes circulantes[2]

Variation des stocks : N - (N-1)		Emplois augmentation (+)		Ressources diminutions (-)
(BC)	Marchandises		ou	
(BD)	Matières premières	512 818	ou	
(BE)	En cours	0	ou	
(BF)	Produits fabriqués	2 934 101	ou	
(A)	**Variation globale nette des stocks**	3 446 920	ou	-

([2]) *A l'exclusion des éléments H.A.O.*

FINANCEMENT DES RESSOURCES ET DES EMPLOIS (TAFIRE)

Variation des créances : N - (N-1)		Emplois augmentation (+)		Ressources diminutions (-)
(BH)	Fournisseurs, avances versées	0	ou	
(BI)	Clients	3 418 800	ou	
(BJ)	Autres créances	6 247 027	ou	
(BU)	Ecart de conversion - Actif	37 981		
(B)	**Variation globale nette des créances**	9 703 808	ou	-

Variation des dettes circulantes : N - (N-1)		Emplois diminution (-)		Ressources augmentation (+)
(DI)	Clients, avances reçues		ou	
(DJ)	Fournisseurs d'exploitation		ou	11 817 652
(DK)	Dettes fiscales		ou	3 391 160
(DL)	Dettes sociales		ou	63 637
(DM)	Autres dettes		ou	0
(DN)	Risques provisionnés		ou	37 981
(DU)	Ecart de conversion - Passif		ou	177 527
(C)	**Variation globale nette des dettes circulantes**	-	ou	15 487 957

VARIATION DU B.F.E= (A) + (B) + (C)		ou	**2 337 229**

CAPACITE D'AUTOFINANCEMENT GLOBALE (C.A.F.G.)

- charges décaissables restantes à l'exclusion des cessions d'actif immobilisé
+ produits encaissables restants

CAFG = EBE

			E. B. E.	38 406 922
(SA) Frais financiers	104 516	(TT)	Transferts de charges d'exploitation	0
(SC) Pertes de change	317 108	(UA)	Revenus financiers	0
(SL) Charges H.A.O.	5 516 965	(UE)	Transferts de charges financières	0
(SQ) Participation	0	(UC)	Gains de change	0
(SR) Impôts sur résultat	22 620 606	(UL)	Produits H.A.O.	0
		(UN)	Transferts de charges H.A.O.	0
Total (I)	**28 559 195**		Total (II)	**38 406 922**

CAFG : Total (II) - Total (I) = 9 847 727 | (N - 1) : 0

0

AUTOFINANCEMENT (A.F.)

AF = CAFG - Distributions de dividendes dans l'exercices ([1])

AF = 9 847 727 - 0 = 9 847 727 | (N - 1) : 0

([1]) *Dividendes mis en paiement au cours de l'exercice y compris les acomptes sur les dividendes*

EXCEDENT DE TRESORERIE D'EXPLOITATION (E.T.E.)

ETE = EBE - VARIATION BFE - Production immobilisée

	N	N-1
excédent brut d'exploitation	38 406 922	-
- Variation du B.F.E. (-si emplois; + si ressources) (-ou+)	2 337 229	
- Production immobilisée	-	
	40 744 152	**-**

TABLEAU FINANCIERS DES RESSOURCES ET DES EMPLOIS (TAFIRE) SYSTEME NORMAL

2e PARTIE / TABLEAU

Réf		Exercice N		Exercice N-1
		Emplois	Ressources	(E -; R +)
	I. INVESTISSEMENTS ET DESINVESTISSEMENTS			
FA	Charges immobilisées (augmentation de l'exercice)			
	Croissance interne			
FB	Acquisitions/cession d'immobilisations incorporelles	7 382 000		
FC	Acquisitions/cession d'immobilisations corporelles	534 658		
	Croissance externe			
FC	Acquisitions/cession d'immobilisations financières	31 192	0	
FF	**INVESTISSEMENT TOTAL**	7 947 850	0	
FG	II. VARIATION DU BSEOIN DE FINANCEMENT D'EXPLOITATION (cf.Supra: Var B.F.E.)	ou	2 337 229	
FH	**A - EMPLOIS ECONOMIQUES A FINANCER (FF + FG)**	5 610 621	0	
FI	III. EMPLOIS/RESSOURCES (B.F., H.A.O.)	ou		
FJ	IV. EMPLOIS FINANCIERS CONTRAINTS(1) remboursement (selon échéancier) des emprunts et dettes financières			
	(1) à l'exclusion des remboursements anticipés portés en VII)			
FK	**B - EMPLOIS TOTAUX A FINANCER**	5 610 621	0	

TABLEAU FINANCIERS DES RESSOURCES ET DES EMPLOIS (TAFIRE)
SYSTEME NORMAL

(suite)

Réf			Exercice N Emplois	Exercice N Ressources	Exercice N-1 (E -; R +)
	V. FINANCEMENT INTERNE				
FL	Dividendes (emplois)/C.A.F.G.(ressources)			9 847 727	
	VI. FINANCEMENT PAR LES CAPITAUX PROPRES				
FM	Augmentations de capital par apports nouveaux			1 600 000	
FN	Subventions d'investissement				
FP	Prélèvements sur le capital (y compris retraits de l'exploitant)				
	VII. FINANCEMENT PAR DE NOUVEAUX EMPRUNTS				
FQ	Emprunts[(2)]				
FR	Autres dettes financières[(2)]				
	(2) remboursements anticipés inscrits séparément en emplois				
FS	**C - RESSOURCES NETTES DE FINANCEMENT**		0	11 447 727	
FT	**D - EXCEDENT OU INSUFFISANCE DE RESSOURCES DE FINANCEMENT (C-B)**		0 ou	5 837 107	
	VIII. VARIATION DE TRESORERIE Trésorerie nette				
FU	à la clôture de l'exercice + ou -	5 837 107			
FV	à l'ouverture de l'exercice + ou -	0			
FW	**Variation de trésorerie** (+si Emploi; - si Ressources)		5 837 107 ou		
	Contrôle : D = VIIIavec signe opposé	0			

Nota: I, IV, V, VI, VII: en termes de flux; II, III, VIII: différences "bilantielles"

CONTRÔLE (à partir des masses des bilans N et N-1)			Emplois		Ressources
Variation du fonds de roulement (FdR)	:	FdR(N)-FdR(N-1)		ou	3 499 877
Variation du B.F. global (B.F.G.)	:	BFG(N)-BFG(N-1)		ou	2 337 229
Variation de la trésorerie (T)	:	T(N)-T(N-1)	5 837 107	ou	
		Total	5 837 107	=	5 837 107

TAXE SUR LA VALEUR AJOUTEE — DECLARATION ANNUELLE

Versements effectués et retenues subies au cours de l'exercice

Période de référence 1	Lignes	N° et date de la quittance 2	Montant du versement 3	TVA retenue à la source 4	Total 5=3+4
Janvier	1				-
Février	2				-
Mars	3				-
Avril	4				-
Mai	5				-
Juin	6				-
Juillet	7				-
Août	8				-
Septembre	9				-
Octobre	10				-
Novembre	11				-
Décembre	12				-
TOTAUX lignes 01 à 12		-	-	-	-

NEANT

SITUATION NETTE DE LA TVA

Crédit de TVA N-1	-
TVA Brute total	
TVA déductible	
TVA nette totale	
TVA versé au cours de l'exercice	-
TVA nette à payer	
Crédit de TVA net à porter	

	Période de référence	Montant (1)	N° et date de la quittance
Versements des droits d'accises effectués en cours d'exercice	Janvier		
	Février		
	Mars		
	Avril		
	Mai		
	Juin		
	Juillet		
	Août		
	Septembre		
	Octobre		
	Novembre		
	Décembre		
	TOTAUX lignes 56 à 64	-	
	Situation nette (ligne 05 col 7 — ligne 65 col 1)		

IMPOTS ET TAXES — DECLARATION ANNUELLE

Versements effectués et retenues subies au cours de l'exercice

Période de référence 1	Lignes	N° et date de la quittance 2	T.U.S. 3	I.R.P.P 4	Total 5=3+4
Janvier	13				-
Février	14				-
Mars (ou ler trimestre)	15				-
Avril	16				-
Mai	17				-
Juin (ou 2éme trimestre)	18				-
Juillet	19				-
Août	20				-
Septembre (ou 3éme trimestre)	21				-
Octobre	22				-
Novembre	23				-
Décembre (ou 4éme trimestre)	24				-
TOTAUX lignes 13 à 24			-	-	-

Versements I.S. au cours de l'exercice

Période de référence 1	Lignes	N° et date de la quittance 2	Montant
Janvier	13		
Février	14		
Mars (ou ler trimestre)	15		
Avril	16		
Mai	17		
Juin (ou 2éme trimestre)	18		
Juillet	19		
Août	20		
Septembre (ou 3éme trimestre)	21		
Octobre	22		
Novembre	23		
Décembre (ou 4éme trimestre)	24		
TOTAUX lignes 13 à 24			-

-

NEANT

DROITS D'ACCISES ET TAXE SUR LA VALEUR AJOUTEE

	CALCUL DES DROITS D'ACCISES						
	Nature du produit (1)	Base brute taxable	Abattement		Base nette taxable (5) = (2-4)	Taux (6)	Montants des droits (7) = (5x6)
			Taux (3)	Montant (4) = (2x3)			
1							
2							
3							
4							
5	TOTAL						

TAXE SUR LA VALEUR AJOUTEE - DECLARATTON ANNUELLE

	NATURE DES OPERATIONS (1)	Lignes	BASES TAXABLES		BASES NON TAXABLES (4)		CUMUL (5)
			TAUX GENERAUX (2)	TAUX ZERO (3)	EXONERES	TAXABLE SOUS CONVENTION	
I	Livraison des biens	6					
	Livraison à soi-même	7					
	Prestations de services	8					
	Prestations à soi-même	9					
	Cession d'éléments d'actifs non exonérés	10					
	Location terrains non aménagés	[illegible]					
	Locations locaux nus	12					
	Autres opérations	13					
	TOTAL DES OPERATIONS	14					
	Droits d'accises	15					
	TOTAL DE LA BASE TAXABLE: Totaux lignes 6 à 18	16					
II							
	CALCUL DE LA TVA BRUTE						
	Montant de la taxe collectée	17					
	TOTAL TVA BRUTE : Totaux lignes 20 et 21	18					
III							
	CALCUL DU PRORATA DEFINITIF						
	CA ouvrant droit à déduction	19					
	CA Total	20					
	Prorata de régularisation en fin d'exercice	21					
IV							
	DEDUCTIONS		**TVA SUR FACTURE**		**TVA DEDUCTIBLE**		
	Sur biens et services ne constituant pas des immobilisations	22					
	Sur biens et services constituant des immobilisations	23					
	Complément de_ TVA à déduire	24					
	Report de crédit de TVA de l'exercice précédent	25					
	TOTAL DES DEDUCTIONS : Totaux lignes 20 à23	26					

NEANT

TABLEAU : ETAT ANNEXE

TABLEAU I : ACTIF IMMOBILISE

Désignation de l'entreprise *HEMLA EP CONGO SA*

Exercice clos le *31 décembre 2017*

SITUATIONS ET MOUVEMENTS / RUBRIQUES	A	AUGMENTATIONS B			DIMINUTIONS C		D+A+B-C
	MONTANT BRUT A L'OUVERTURE DE L'EXERCICE	Acquisitions Apports Créations	Virement de poste à poste	Suite à une réévaluation pratiquée au cours de l'exercice	Cessions Scissions Hors service	Virement de poste à poste	MONTANT BRUT A LA CLOTURE DE L'EXERCICE
CHARGES IMMOBILISEES	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Frais d'établissement et charges à répartir							0
Primes de remboursement des obligations							0
IMMOBILISATIONS INCORPORELLES	**0**	**7 382 000**	**0**	**0**	**0**	**0**	**7 382 000**
Frais de recherches et développement							0
Brevets, licences, logiciels		7 382 000					7 382 000
Fonds commercial							0
Autres immobilisations incorporelles							0
IMMOBILISATIONS CORPORELLES	**0**	**534 658**	**0**	**0**	**0**	**0**	**534 658**
Terrains							
Bâtiments							
Installations et agencements		525 953					525 953
Matériel							0
Matériel de transport		8 705					8 705
AVANCES ET ACOMPTES VERSES SUR IMMOBILISATIONS							0
IMMOBILISATIONS FINANCIERES	**0**	**31 192**	**0**	**0**	**0**	**0**	**31 192**
Titres de participation							0
Autres immobilisations financières		31 192					31 192
TOTAL GENERAL	**0**	**7 947 850**	**0**	**0**	**0**	**0**	**7 947 850**

Nota : Inscrire au bas du tableau, s'ils sont significatifs, les montats (par postes référencés) d'immobilisations incorporelles et corporelles en cours à la clôture

TABLEAU 2 : AMORTISSEMENTS

Désignation de l'entreprise *HEMLA EP CONGO SA*

Exercice clos le *31 décembre 2017*

RUBRIQUES \ SITUATIONS ET MOUVEMENTS	A AMORTISSEMENTS CUMULES A L'OUVERTURE DE L'EXERCICE	B AUGMENTATIONS DOTATIONS DE L'EXERCICE	C DIMINUTIONS: Amortissements relatifs aux éléments sortis de l'Actif	D+A+B-C CUMUL DES AMORTISSEMENTS A LA CLOTURE DE L'EXERCICE
CHARGES IMMOBILISEES				
Frais d'établissement et charges à répartir				0
Primes de remboursement des obligations				0
TOTAL	**0**	**0**	**0**	**0**
IMMOBILISATIONS INCORPORELLES				
Frais de recherches et développement				0
Brevets, licences, logiciels		930 591		930 591
Fonds commercial				0
Autres immobilisations incorporelles				
TOTAL (I)	**0**	**930 591**	**0**	**930 591**
IMMOBILISATIONS CORPORELLES				
Terrains				0
Bâtiments				0
Installations et agencements		66 303		66 303
Matériel				0
Matériel de transport		8 705		8 705
TOTAL (II)	**0**	**75 008**	**0**	**75 008**
TOTAL (I+II)		**1 005 599**		**1 005 599**

Total des Dotations de l'exercice	1 005 599

TABLEAU 3 : PLUS-VALUES ET MOINS-VALUES DE CESSION (I)

Désignation de l'entreprise *HEMLA EP CONGO SA*

Exercice clos le *31 décembre 2017*

	MONTANT BRUT A	AMORTISSE-MENTS PRATIQUES B	VALEUR COMPTABLE NETTE C=A-B	PRIX DE CESSION D	PLUS / MOINS VALUE E=D-C
IMMOBILISATIONS INCORPORELLES					
Frais de recherches et développement					
Brevets, licences, logiciels					
Fonds commercial					
Autres immobilisations incorporelles					
IMMOBILISATIONS CORPORELLES					
Terrains					
Bâtiments					
Installations et agencements					
Matériel					
Matériel de transport					
IMMOBILISATIONS FINANCIERES					
Titres de participation					
Autres immobilisations financières		0	0	0	0
TOTAL	**0**	**0**	**0**	**0**	**0**

NEANT

(I) Par poste du bilan

TABLEAU 4 : PROVISIONS INSCRITES AU BILAN

Désignation de l'entreprise *HEMLA EP CONGO SA*

Exercice clos le *31 décembre 2017*

SITUATIONS ET MOUVEMENTS / NATURE	A	B			C			D+A+B-C
	PROVISION A L'OUVERTURE DE L'EXERCICE	AUGMENTATIONS : DOTATIONS			DIMINUTIONS : REPRISES			PROVISION A LA CLOTURE DE L'EXERCICE
		D'EXPLOI-TATION	FINANCIERES	HORS ACTIVITE ORDINAIRES	D'EXPLOI-TATION	FINANCIERES	HORS ACTIVITE ORDINAIRES	
1. Provisions réglementées	0							0
2. Provisions financières pour risques et charges	0							0
3. Provisions pour dépréciaiton des immobilisations	0							0
TOTAL (I)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4. Dépréciation des stocks	0							0
5. Dépréciations et risques provisionnés (Tiers)	0		37 981					37 981
6. Dépréciations et risques provisionnés (Trésorerie)	0							0
TOTAL (II)	**0**	**0**	**37 981**	**0**	**0**	**0**	**0**	**37 981**
TOTAL (I) + (II)	**0**	**0**	**37 981**	**0**	**0**	**0**	**0**	**37 981**

TABLEAU 5 : BIENS PRIS EN CREDIT BAIL ET CONTRATS ASSIMILES

Désignation de l'entreprise *HEMLA EP CONGO SA*
Exercice clos le *31 décembre 2017*

SITUATIONS ET MOUVEMENTS RUBRIQUES	NATURE DU CONTRAT (I;M;A) (I)	A	AUGMENTATIONS B			DIMINUTIONS C		D+A+B-C
		MONTANT BRUT A L'OUVERTURE	Acquisitions Apports Créations	Virement de poste à poste	Suite à une réévaluation pratiquée au cours de l'exercice	Cessions Scissions Hors service	Virement de poste à poste	**MONTANT BRUT A LA CLOTURE**
IMMOBILISATIONS INCORPORELLES		-	-	-	-	-	-	-
Brevets, licences, logiciels		-	-	-	-	-	-	-
Fonds commercial		-	-	-	-	-	-	-
Autres immobilisations incorporelles		-	-	-	-	-	-	-
IMMOBILISATIONS CORPORELLES		-	-	-	-	-	-	-
Terrains		-	-	-	-	-	-	-
Bâtiments		-	-	-	-	-	-	-
Installations et agencements		-	-	-	-	-	-	-
Matériel		-	-	-	-	-	-	-
Matériel de transport		-	-	-	-	-	-	-
TOTAL (I) + (II)		**0**	**0**	**0**	**0**	**0**	**0**	**0**

NEANT

(I) I : crédit-bail immobilier; M : crédit-bail mobilier; A : Autres contratcs (dédoubler le poste si montants significatifs)

TABLEAU 6 : ECHEANCES DES CREANCES A LA CLOTURE DE L'EXERCICE

Désignation de l'entreprise *HEMLA EP CONGO SA*
Exercice clos le *31 décembre 2017*

CREANCES	MONTANT BRUT	ANALYSE PAR ECHEANCES				AUTRES ANALYSES		
		A UN AN AU PLUS	DONT ECHUES	A PLUS D'UN AN ETA DEUX ANS AU PLUS	A PLUS DE DEUX ANS	MONTANTS EN DEVISES	MONTANTS ENVERS LES ENTREPRISES LIEES	MONTANTS REPRESENTES PAR EFFETS
CREANCES DE L'ACTIF IMMOBILISE (I)	**0**	**0**	**0**	**0**				
Prêts (I)								
Créances rattachées à des participations								
Autres immobilisations financières	31 192	31 192						
CREANCES DE L'ACTIF CIRCULANT (II)	**9 665 827**	**9 665 827**	**0**	**0**	**0**	**0**	**0**	**0**
Fournisseurs	0	0						
Clients et comtpes rattachés	3 418 800	3 418 800						
Personnel	96 396	96 396						
Sécurité sociale et autres organismes sociaux	0	0						
Etat		0						
Organismes internationaux								
Associés et Groupe	5 792 334	5 792 334						
Débiteurs divers	341 545	341 545						
Créances H.A.O.								
Charges constatées d'avance	16 752	16 752						
TOTAL (I) + (II)	**9 665 827**	**9 665 827**	**0**	**0**	**0**	**0**	**0**	**0**

(I) I : Prêts accordés en cours d'exercice: montant; remboursement obtenus en cours d'exercice : montant

TABLEAU 7 : ECHEANCES DES DETTES A LA CLOTURE DE L'EXERCICE

Désignation de l'entreprise *HEMLA EP CONGO SA*
Exercice clos le *31 décembre 2017*

DETTES	MONTANT BRUT	ANALYSE PAR ECHEANCES				AUTRES ANALYSES		
		A UN AN AU PLUS		A PLUS D'UN AN ETA DEUX ANS AU PLUS	. A PLUS DE DEUX ANS	MONTANTS EN DEVISES	MONTANTS ENVERS LES ENTREPRISES LIEES	MONTANTS REPRESENTES PAR EFFETS
			DONT ECHUES					
DETTES FINANCIERES ET RESSOURCES ASSIMILEES								
Emprunts obligataires convertibles (I)								
Autres emprunts obligatoires								
Emprunts et dettes des établissements de crédit (I)								
Autres dettes financières (I) (2)								
TOTAL (I)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Dettes de crédit - bail immobilier								
Dettes de crédit - bail mobilier								
Dettes sur contrats assimilés								
TOTAL (II)	0	0	0	0	0	0	0	0
DETTES DU PASSIF CIRCULANT								
Fournisseurs et comptes rattachés	11 817 652	11 817 652						
Clients								
Personnel	56 355	56 355						
Sécurité sociale et organismes sociaux	7 282	7 282						
Etat	3 391 160	3 391 160						
Organismes internationaux								
Associés et Groupe								
Créditeurs divers		0						
Dettes H.A.O.								
Produits constatés d'avance								
TOTAL (III)	**15 272 449**	**15 272 449**	0	0	0	0	0	0
TOTAL (I) + (II) + (III)	**15 272 449**	**15 272 449**	**0**	**0**	**0**	**0**	**0**	**0**

(I) Emprunts souscrits en cours d'exercice : *0* / Emprunts remboursés en cours d'exercice : *0* /

(2) Total des dettes envers les associés (personnes physiques)

TABLEAU 8 : CONSOMMATIONS INTERMEDIAIRES DE L'EXERCICE

(comtpes spécifiques de)

Désignation de l'entreprise *HEMLA EP CONGO SA*

Exercice clos le *31 décembre 2017*

NATURE	N° DE COMPTE	MONTANT (en USD)
EAU	6051	0
ELECTRICITE	6052	0
AUTRES ENERGIES	6053	373
FOURNITURES D'ENTRETIEN NON STOCKABLES	6054	0
FOURNITURES DE BUREAU NON STOCKABLES	6055	10 933
PETIT MATERIEL ET OUTILLAGE	6056	2 047
TRANSPORTS POUR LE COMPTE DE TIERS	613	0
TRANSPORT DU PERSONNEL	614	0
ENTRETIEN, REPARATIONS DES BIENS IMMOBILIERS	6241	0
ENTRETIEN, REPARATIONS DES BIENS MOBILIERS	6242	0
PUBLICITE, PUBLICATIONS, RELATIONS PUBLIQUES	627	96 374
FRAIS DE TELECOMMUNICATIONS	628	6 365
REMUNERATIONS D'INTERMEDIAIRES ET DE CONSEILS	632	79 944

TABLEAU 9 : REPARTITION DU RESULTAT ET AUTRES ELEMENTS CARACTERISTIQUES DES CINQ DERNIERS EXERCICES

Désignation de l'entreprise *HEMLA EP CONGO SA*

Exercice clos le *31 décembre 2017*

EXERCICES CONCERNES (I) NATURE DES INDICATIONS	2 016	2 015	2 014	2 013	2 012
STRUCTURE DU CAPITAL A LA CLOTURE DE L'EXERCICE (2)					
Capital social (dont USD 62 500 non appelé)……………………………………………..	1 600 000				
Actions ordinaires ………………………………………………………………………………					
Actions à dividendes prioritaires (A.D.P.) sans droit de vote …………………………………					
Actions nouvelles à émettre …………………………………………………………………….					
par conversion d'obligations …………………………………….					
par exercice de droits de souscription …………………………					
OPERATIONS ET RESULTATS DE L'EXERCICE (3)					
Chiffre d'affaires hors taxes …………………………………………………………………….	68 351 206				
Résultat des activités ordinaires (RAO) hors dotations et reprises	37 985 298				
(exploitation et financières) ……………………………………………………………………..					
Participation des travailleurs aux bénéfices ……………………………………………………..					
Impôts sur le résultat …………………………………………………………………………….	22 620 606				
Résultat net (4) …………………………………………………………………………………..	8 842 128				
RESULTATS PAR ACTION					
Résultat distribué (5) …………………………………………………………………………….					
Dividende attribué à chaque action …………………………………………………………….					
PERSONNEL ET POLITIQUE SALARIALE					
Effectif moyen des travailleurs au cours de l'exercice (6) ……………………………………..	7				
Effectif moyen de personnel extérieur ………………………………………………………….	2				
Masse salariale dsitribuée au cours de l'exercice (7) …………………………………………..	855 713				
Avantages sociaux versés au cours de l'exercice (8) (sécurité sociale, œuvres sociales) .	88 109				
Personnel extérieur facturé à l'entreprise (9) ………………………………………………….	118 664				

1) Y compris l'exercice dont els états financiers sont soumis à l'approbation de l'Assemblée
2) Indication en cas de libération partielle du capital du montant du capital non appelé
3) Les éléments de cette rubrique sont ceux figurant au compte de résultat
4) Le résultat, lorsque'il est négatif, doit être mis entre parenthèses
5) L'exercice N correspond au dividende proposé du dernier exercice
6) Personnel propre
7) Total des comptes 661, 662, 663
8) Total des comptes 664, 668
9) Compte 667.

TABLEAU 10 : PROJET D'AFFECTATION DU RESULTAT DE L'EXERCICE

Désignation de l'entreprise *HEMLA EP CONGO SA*
Exercice clos le *31 décembre 2017*

AFFECTATIONS		MONTANT (I)	ORIGINES		MONTANT (I)
Réserve légale		320 000	Report à nouveau antérieur (pertes)		
Réserves statutaires ou contractuelles			Report à nouveau (bénéficiaire)		
Autres réserves (disponibles)			Résultat net de l'exercice		8 842 128
Dividendes (2)		8 500 000	Prélèvements sur les réserves (3)		
Autres affectations					
Report à nouveau		22 128			
	TOTAL (A)	**8 842 128**	**Contrôle : Total A = Total B**	**TOTAL (B)**	**8 842 128**

1) Les montants négatifs sont à porter entre parenthèses ou précédés d'un signe (-)

8 842 128,29

2) S'il existe plusieurs catégories d'ayant droits aux dividendes, indiquer le montant pour chacune d'elles

-

3) Indiquer les postes de réserves sur lesquels les prélèvements sont effectués

TABLEAU 11 : PERSONNEL

Désignation de l'entreprise *HEMLA EP CONGO SA*
Exercice clos le *31 décembre 2017*

EFFECTIF ET MASSE SALARIALE / QUALIFICATIONS	EFFECTIFS							MASSE SALARIALE						
	NATIONAUX		AUTRES ETATS DE LA REGION		HORS REGION		TOTAL	NATIONAUX		AUTRES ETATS DE LA REGION		HORS REGION		TOTAL
	M	F	M	F	M	F		M	F	M	F	M	F	
a. personnel propre							-							
1. CADRES SUPERIEURS	2						2							
2. TECHNICIENS SUPERIEURS ET CADRES MOYENS	1						1							
3. TECHNICIENS, AGENTS DE MAITRISE ET OUVRIERS QUALIFIES		1					1	855 713						855 713
4. EMPLOYES, MANŒUVRES, OUVRIERS ET APPRENTIS	2	1					3							
TOTAL (I)	5	2	-	-	-		7							855 713
PERMANENTS	5	2	-	-										
SAISONNIERS														

b. personnel extérieur	M	F	M	F	M	F		FACTURATION A L'ENTREPRISE
1. CADRES SUPERIEURS	2	-	-	-	-	-		
2. TECHNICIENS SUPERIEURS ET CADRES MOYENS	-	-	-	-	-	-		
3. TECHNICIENS, AGENTS DE MAITRISE ET OUVRIERS QUALIFIES	-	-	-	-	-	-		118 664
4. EMPLOYES, MANŒUVRES, OUVRIERS ET APPRENTIS		-	-	-				
TOTAL (2)	2	-	-	-			-	118 664
PERMANENTS	2							
SAISONNIERS								
TOTAL (I + 2)	7	2	-	-				974 378

TABLEAU 12 : VENTE DES MARCHANDISES

Désignation de l'entreprise *HEMLA EP CONGO SA*
Exercice clos le *31 décembre 2017*

DESIGNATION DES MARCHANDISES	UNITE DE QUANTITE CHOISIE	MARCHANDISES VENDUES DANS LE PAYS		MARCHANDISES VENDUES DANS LES AUTRES PAYS DE LA CEMAC		MARCHANDISES VENDUES HORS CEMAC	
		Quantité	Valeur	Quantité	Valeur	Quantité	Valeur
NEANT							
NON VENTILE							
TOTAL		0	0	0	0	0	0

TABLEAU 13 : PRODUCTION DE L'EXERCICE

Désignation de l'entreprise *HELMA EP CONGO SA*
Exercice clos le *31 décembre 2017*

DESIGNATION DU PRODUIT	UNITE DE QUANTITE CHOISIE	PRODUCTION VENDUE DANS LE PAYS		PRODUCTION VENDUE DANS LES AUTRES PAYS DE LA REGION		PRODUCTION VENDUE HORS REGION		PRODUCTION IMMOBILISEE		STOCK OUVERTURE DE L'EXERCICE		STOCK CLOTURE DE L'EXERCICE	
		Quantité	Valeur	Quantité	Valeur	Quantité	Valeur	Quantité	Valeur	Quantité	Valeur	Quantité	Valeur
Vente hydrocarbure	Bbls		33 035 609			340 000	35 315 597			0	0	44 939	2 934 101
NON VENTILE													
TOTAL		0	0	0	0	0	0	0	0	0	0	0	0

TABLEAU 14 : ACHATS DESTINES A LA PRODUCTION

Désignation de l'entreprise *HEMLA EP CONGO SA*
Exercice clos le *31 décembre 2017*

DESIGNATION DES MATIERES ET PRODUITS	UNITE DE QUANTITE CHOISIE	ACHATS EFFECTUES AU COURS DE L'EXERCICE						VARIATION DES STOCKS
		PRODUITS DE L'ETAT		PRODUITS IMPORTES				
				ACHETES DANS L'ETAT		ACHETES HORS DE L'ETAT		
		Quantité	Valeur	Quantité	Valeur	Quantité	Valeur	(en valeur)
NEANT								
NON VENTILE								
TOTAL		0	0	0	0	0	0	0

ETAT ANNEXE

Les notes ci-après font partie intégrante des comptes annuels de la société HEMLA EP CONGO SA.
L'exercice a débuté le 29/12/2016 et s'est achevé le 31/12/2017, soit une durée de 12 mois
Les comptes annuels ont été arrêtés le 31/12/2017

I INFORMATIONS GENERALES

A - Activité de l'entreprise

Recherche, Production, Transport, Commercialisation des Hydrocarbures

B - Evénements marquants de l'exercice

Néant

C - Situation fiscale

Néant

D - Evénements postérieurs à la clôture de l'exercice

Néant

II INFORMATIONS OBLIGATOIRES

A - Régles et méthodes comptables

II A 1 Méthode générale d'évaluation appliquée par l'entreprise

La société HELMA EP CONGO SA a tenu sa comptabilité selon le système et droit comptable de l' OHADA.

La comptabilité est tenue chronologiquement et permet d'éditer les journaux, les grands livres et les balances.

Les états financiers sont établis en application du système normal.

La monnaie de tenue de comptes et le Dollar Americain (USD).

II A 2 Méthode spécifiques d'évaluation

II A 2 1 Charges immobilisées
Les charges immobilisées correspondent aux frais de constitution de la société

II A 2 2 Immobilisations incorporelles
Les immobilisations incorporelles sont inscrites au bilan à la valeur d'acquisition et sont amorties par Unité de Production.

II A 2 3 Immobilisations corporelles
Les immobilisations corporelles sont comptabilisées au bilan à la valeur d'acquisition;
Les immoblisations corporelles pétrolières sont amorties par Unité de Production et autres immobilisations corporelles sont amorties en linéaires sur la durée de vie probable.
Les taux d'amortissements utlisées sont les suivants :

Amenagement de bureau	*10%*
Matériel de bureau	*25%*
Matériel informatique	*25%*
Mobilier de bureau	*15%*

II A 2 4 Immobilisations financières
Néant

II A 2 5 Stocks
Les stocks d'Hydrocarbure sont valorisées à la dernière cotation Platts dimunuée des frais de commercialisation

II A 2 6 Créances et dettes
Les créances et les dettes sont valorisées à la valeur nominale. Les créances et dettes en monnaie étrangère sont converties au taux de clôture de l'exercice. Les pertes latentes de change et les gains latents de change réalisés à la clôture sont inscrits respectivement à l'actif et au passif du bilan.

II A 2 7 Trésorerie
La trésorerie est valorisée à la valeur nominale. La trésorerie en monnaie étrangère est convertie au taux clôture de l'exercice. Les pertes et les gains de change réalisésà la clôture sont inscrits directement au compte de résultat.

II A 2 8 Dettes Financières
Néant

II A 2 9 provisions pour risque et charges
Néant

II A 3 Dérogations utilisées par l'entreprise

Néant

II A 4 Méthodes de présentation, modifications intervenues depuis le dernier exercice

Néant

II A 5 Dérogations aux régles de présentation

Néant

B - Informations complémentaires relatives au bilan et au compte de résultat

II B 1 Circonstances exceptionnelles susceptibles de fausser la comparaison des états financiers d'un exercice à l'autre

Néant

II B 2 Informations sur les réévaluations effectuées par l'entreprise

Néant

II B 3 Dettes garanties par des suretés réelles

Néant

II B 4 Engagements financiers

Néant

II B 5 Eléments constitutifs du fonds commercial

Néant

II B 6 Commentaires sur les éventuelles dérogations en matiére de frais de recherche et de développement

Néant

II B 7 Contrats avec clause de réserve de propriété
Néant

II B 8 Différence significative d'evaluation de stock
Néant

II B 9 Différence sur la nature, le montant et le traitement comptable

II B 9 1 Des frais d'établissement
Néant

II B 9 2 Des charges à répartir sur plusieurs exercices
Néant

II B 10 Indications sur la méthode de calcul du bénéfice partiel sur opérations pluri-exercices
Néant

II B 11 Information sur les résultats d'opérations faites en commun
Néant

II B 12 Eléments d'informations nécessaires à la statistique nationale

Détail des produits	Montant Etat	Montant autres Etats de la région	Montant Hors Région
Chiffre d'affaires Dont,	33 035 609	Néant	35 315 597
Redevances pour brevets, concessions, licences marques et droits similaires			
Redevances pour locations de terrains agricoles			
Subventions d'exploitation sur les produits :	Néant	Néant	Néant
Production immobilisée :			
Part des frais de recherche et de développement dans la production immobilisée	Néant	Néant	Néant
Part des frais de recherche miniére et pétroliére dans la production immobilisée	Néant	Néant	Néant
Produits financiers			
Revenus des participations	Néant	Néant	Néant
Gains sur titres de placement cédés	Néant	Néant	Néant
Part des intérêts échus et encaissés au cours de l'exercice	Néant	Néant	Néant
Indemnités de fonctions et autres rémunérations d'administrateurs reçus	Néant	Néant	Néant
Détail des produits hors activités ordinaires			
Produits des cessions d'immobilisations	Néant	Néant	Néant

Détail des charges	Montant Etat	Montant autres Etats de la région	Montant Hors Région
Frais de transport sur achats	125 515	Néant	Néant
Frais de transport sur ventes	Néant	Néant	Néant
Primes d'assurances	Néant	Néant	Néant
Frais de location des terrains agricoles	Néant	Néant	Néant
Cotisations	Néant	Néant	Néant
Dons	Néant	Néant	Néant
Cotisations sociales effectives	Néant	Néant	Néant
Cotisations sociales imputées	Néant	Néant	Néant
Salaires et traitements bruts	Néant	Néant	Néant
Impôts et taxes sur les produits	11 199 897	Néant	Néant
Impôts fonciers	Néant	Néant	Néant
Pertes sur créances clients	Néant	Néant	Néant
Pertes sur titres de placement cédés	Néant	Néant	Néant
Dotation pour dépréciation des immobilisations financiéres	Néant	Néant	Néant
Dotation pour dépréciation des titres de placement	Néant	Néant	Néant
Intérêts échus versés	Néant	Néant	Néant
Indemnités de fonction et autres rémunérations d'administrateurs	Néant	Néant	Néant
Contenu et montants des éléments constitutifs du poste Charges Hors Activités Ordinaires	Néant	Néant	Néant
Valeur comptable des cessions d'immobilisations	Néant	Néant	Néant

informations spécifiques

Biens acquis d'occasion	Montant Etat	Montant autres Etats de la région	Montant Hors Région
Néant			

Acquisistions et cessions d'œuvre d'art	Montant acquisitions	Montant cessions
Néant		

Échéances initiales des créances à deux ans au plus	Échéances
Clients	3 418 800
Avances fournisseurs	Néant
Personnel	96 396
Etat	0
Autres créances	6 133 880
Charges payées d'avance	16 752

Échéances initiales des créances à plus de deux ans	Échéances
Clients	Néant
Avances fournisseurs	Néant
Personnel	Néant
Etat	Néant
Charges payées d'avance	Néant

Échéances initiales des dettes à deux ans au plus	Échéances
Fournisseurs	11 817 652
Personnel	56 355
Organismes sociaux	7 282
Etat	3 391 160
Associés	Néant
Divers	Néant

Échéances initiales des dettes à plus de deux ans	Échéances
Fournisseurs	Néant
Personnel	Néant
Organismes sociaux	Néant
Etat	Néant
Associés	Néant
Divers	Néant

TVA FACTUREE	TVA RECUPERABLE	TVA SUPPORTEE NON DEDUCTIBLE
Néant	Néant	Néant

C - Pour les sociétés

II C1 Liste des filiales et participations

Néant

II C2 Avances et crédits accordés aux associés

Néant

III INFORMATIONS D'IMPORTANCE SIGNIFICATIVE

A - Subventions d'investissements et provisions réglementées

Néant

B - Ecarts de conversion

Néant

C - Créances et dettes échues au cours de l'exercice

Néant

D - Analyse des impôts différés

Néant

E - Comptes courants des associés

Noms	Clause particuliéres	Montant	Terme
Néant			

F - Créances et dettes liées à des participations

Néant

G - Détail des réserves indisponibles et des réserves libres

Néant

H - Montant global des rémunérations des membres des organes de direction, d'administration et de surveillance

Néant

HEMLA E&P CONGO S.A.

Rapports du commissaire aux comptes sur les états financiers annuels et spécial sur les conventions réglementées

Exercice clos le 31 décembre 2017

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HEMLA E&P CONGO S.A.

RAPPORT DU COMMISSAIRE AUX COMPTES
ETATS FINANCIERS ANNUELS

EXERCICE CLOS LE 31 DECEMBRE 2017

Aux actionnaires de la société HEMLA E&P CONGO S.A

En exécution de la mission qui nous a été confiée par votre assemblée générale ordinaire, nous vous présentons notre rapport relatif à l'exercice clos le 31 décembre 2017, sur :

- le contrôle des états financiers annuels de la société HEMLA E&P CONGO S.A tels qu'ils sont joints au présent rapport,
- les autres informations et les vérifications spécifiques prévues par la loi et les règlements.

I - AUDIT DES ETATS FINANCIERS ANNUELS

Opinion

Nous avons effectué l'audit des états financiers annuels de la société HEMLA E&P CONGO S.A, comprenant le bilan au 31 décembre 2017, le compte de résultat, le tableau financier des ressources et emplois, ainsi que l'état annexé. Ces états financiers annuels présentent un total bilan de USD 25 930 millions, un bénéfice de l'exercice de USD 8 842 millions.

À notre avis, les états financiers annuels sont réguliers et sincères et donnent une image fidèle du résultat des opérations de l'exercice écoulé ainsi que de la situation financière et du patrimoine de la société à la fin de cet exercice conformément aux règles et méthodes comptables éditées par l'Acte uniforme de l'OHADA portant organisation et harmonisation des comptabilités des entreprises.

Fondement de l'opinion

Nous avons effectué notre audit selon les normes internationales d'audit (ISA). Les responsabilités qui nous incombent en vertu de ces normes sont plus amplement décrites dans la section «Responsabilités du commissaire aux comptes relatives à l'audit des états financiers annuels» du présent rapport. Nous sommes indépendants de la société conformément aux règles d'indépendance qui encadrent le commissariat aux comptes et nous avons satisfait aux autres responsabilités éthiques qui nous incombent selon ces règles. Nous estimons que les éléments probants que nous avons obtenus sont suffisants et appropriés pour fonder notre opinion d'audit.

Responsabilité du Conseil d'Administration relatives aux états financiers annuels

Les états financiers annuels ont été établis et arrêtés par le Conseil d'Administration conformément aux règles et méthodes comptables prévues par l'Acte Uniforme de l'OHADA relatif au Droit Comptable.

Le Conseil d'Administration est responsable de l'établissement et de la présentation sincère des états financiers annuels conformément aux règles et méthodes comptables prévues par l'Acte Uniforme de l'OHADA relatif au Droit, ainsi que du contrôle interne qu'elle estime nécessaire pour permettre la préparation d'états financiers annuels, ainsi que du contrôle interne qu'elle estime nécessaire à l'établissement d'états financiers annuels ne comportant pas d'anomalies significatives, que celles-ci proviennent de fraudes ou résultent d'erreurs.

Lors de l'établissement des états financiers annuels, il incombe au Conseil d'Administration d'évaluer la capacité de la société à poursuivre son exploitation, de fournir, le cas échéant, des informations relatives à la continuité d'exploitation et d'appliquer le principe comptable de continuité d'exploitation, sauf si la direction a l'intention de mettre la société en liquidation ou de cesser ses activités ou s'il n'existe aucune autre solution alternative réaliste qui s'offre à elle.

Il incombe au Conseil d'Administration de surveiller le processus d'élaboration de l'information financière de la société.

Responsabilités du commissaire aux comptes relatives à l'audit des états financiers

Nos objectifs sont d'obtenir l'assurance raisonnable que les états financiers annuels pris dans leur ensemble ne comportent pas d'anomalies significatives, que celles-ci proviennent de fraudes ou résultent d'erreurs, et d'émettre un rapport d'audit contenant notre opinion. L'assurance raisonnable correspond à un niveau élevé d'assurance, qui ne garantit toutefois pas qu'un audit réalisé conformément aux normes ISA permettra de toujours détecter toute anomalie significative existante.

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Les anomalies peuvent provenir de fraudes ou résulter d'erreurs et sont considérées comme significatives lorsqu'il est raisonnable de s'attendre à ce que, prises individuellement ou en cumulé, elles puissent influencer les décisions économiques que les utilisateurs des états financiers annuels prennent en se fondant sur ceux-ci.

Dans le cadre d'un audit réalisé conformément aux normes ISA et tout au long de celui-ci, nous exerçons notre jugement professionnel et faisons preuve d'esprit critique. En outre:

- nous identifions et évaluons les risques que les états financiers annuels comportent des anomalies significatives, que celles-ci proviennent de fraudes ou résultent d'erreurs, définissons et mettons en œuvre des procédures d'audit en réponse à ces risques, et recueillons des éléments probants suffisants et appropriés pour fonder notre opinion. Le risque de non-détection d'une anomalie significative provenant d'une fraude est plus élevé que celui d'une anomalie significative résultant d'une erreur, car la fraude peut impliquer la collusion, la falsification, les omissions volontaires, les fausses déclarations ou le contournement du contrôle interne ;

- nous prenons connaissance du contrôle interne pertinent pour l'audit afin de définir des procédures d'audit appropriées en la circonstance, mais non dans le but d'exprimer une opinion sur l'efficacité du contrôle interne de la société;

- nous apprécions le caractère approprié des méthodes comptables retenues et le caractère raisonnable des estimations comptables faites par la direction, de même que des informations fournies les concernant par cette dernière ;

- nous concluons quant au caractère approprié de l'application par la direction du principe comptable de continuité d'exploitation et, selon les éléments probants recueillis, quant à l'existence ou non d'une incertitude significative liée à des événements ou situations susceptibles de jeter un doute important sur la capacité de la société à poursuivre son exploitation. Si nous concluons à l'existence d'une incertitude significative, nous sommes tenus d'attirer l'attention des lecteurs de notre rapport sur les informations fournies dans les états financiers annuels au sujet de cette incertitude ou, si ces informations ne sont pas adéquates, d'exprimer une opinion modifiée. Nos conclusions s'appuient sur les éléments probants recueillis jusqu'à la date de notre rapport d'audit. Cependant, des conditions ou événements futurs pourraient conduire l'entité à cesser son exploitation ;

- nous apprécions la présentation d'ensemble, la structure et le contenu des états financiers annuels, y compris les informations fournies dans les états financiers annuels, et apprécions si les états financiers annuels les opérations et événements les sous-jacents d'une manière telle qu'ils donnent une présentation sincère.

Nous communiquons aux personnes constituant le gouvernement d'entreprise notamment l'étendue des travaux d'audit et du calendrier de réalisation prévus et les constations importantes, y compris toute faiblesse significative du contrôle interne, relevée lors de notre audit.

II- AUTRES INFORMATIONS ET VERIFICATIONS SPECIFQUES PREVUES PAR LA LOI ET LES REGLEMENTS

La responsabilité des autres informations incombe au Conseil d'Administration. Les autres informations se composent des informations contenues dans le rapport de gestion mais ne comprennent pas les états financiers annuels et notre rapport du commissaire aux comptes sur ces états financiers annuels.

Notre opinion sur les états financiers annuels, ne s'étend pas aux autres informations et nous n'exprimons aucune forme d'assurance que ce soit sur ces informations.

Dans le cadre de notre mandat de commissariat aux comptes, notre responsabilité est, d'une part, de faire les vérifications spécifiques prévues par la loi et les règlements, et ce faisant, à vérifier la sincérité et la concordance avec les états financiers annuels des informations données dans le rapport de gestion du Conseil d'Administration, et dans les documents adressés aux actionnaires sur la situation financière et les états financiers annuels, et à vérifier, dans tous leurs aspects significatifs, le respect de certaines obligations légales et réglementaires. D'autre part, notre responsabilité consiste également à lire les autres informations et, par conséquent, à apprécier s'il existe une incohérence significative entre celles-ci et les états financiers ou la connaissance que nous avons acquise lors de l'audit, ou encore si les autres informations semblent comporter une anomalie significative.

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Si à la lumière des travaux que nous avons effectués lors de nos vérifications spécifiques ou sur les autres informations, nous concluons à la présence d'une anomalie significative, nous sommes tenus de signaler ce fait. Nous n'avons rien à signaler à cet égard.

Le Commissaire aux Comptes
ERNST & YOUNG
Agréé CEMAC n°SEC 082

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Ludovic NGATSE
Expert-Comptable Agréé CEMAC n°EC146
Associé

Pointe-Noire, le 24 Juillet 2018

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HEMLA E&P CONGO S.A.

RAPPORT DU COMMISSAIRE AUX COMPTES SUR LES CONVENTIONS REGLEMENTEES

EXERCICE CLOS LE 31 DECEMBRE 2017

En notre qualité de Commissaire aux comptes de votre société, nous vous présentons notre rapport sur les conventions réglementées.

Il ne nous appartient pas de rechercher l'existence de conventions, mais de vous communiquer, sur la base des informations qui nous ont été données, les caractéristiques et les modalités essentielles de celles dont nous avons été avisés, sans avoir à nous prononcer sur leur utilité et leur bien-fondé. Il vous appartient d'apprécier l'intérêt qui s'attachait à la conclusion de ces conventions en vue de leur approbation.

Par ailleurs, il nous appartient, le cas échéant, de vous communiquer les informations relatives à l'exécution, au cours de l'exercice écoulé, des conventions déjà approuvées par l'assemblée générale.

Nous avons effectué nos travaux selon les normes de la profession ; ces normes requièrent la mise en œuvre de diligences destinées à vérifier la concordance des informations qui nous ont été données avec les documents de base dont elles sont issues.

1. CONVENTIONS SOUMISES A L'APPROBATION DE L'ASSEMBLEE GENERALE

1.1 CONVENTION AUTORISEE AU COURS DE L'EXERCICE ECOULE

Nous vous informons qu'il ne nous a été donné avis d'aucune convention autorisée au cours de l'exercice écoulé à soumettre à l'approbation de l'assemblée générale en application des dispositions des articles 438 à 448 de l'Acte uniforme de l'OHADA relatif au droit des sociétés commerciales et du GIE.

Membre du réseau Ernst & Young Global Limited
Service des impôts : UGE BRAZZAVILLE
Régime d'imposition : REEL
NIU n°M2005110000287160
Agrément CEMAC n°SEC 062
R.C.C.M. CG/BZV/07 B 569
S.A. au capital de FCFA 10.000.000

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2. CONVENTIONS EN ATTENTE D'APPROBATION AVEC EXECUTION AU COURS DE L'EXERCICE ECOULE

- **CONVENTION DE TRESORERIE AVEC PETROMAL**

Société concernée	:	PETROMAL représentée par Monsieur EYAS A.A. ALHOMOUZ RANDA
Nature et objet	:	Convention de trésorerie
Modalité et rémunération	:	Comptes rémunérés au taux des avances en compte courant sur fonds d'Etat de la Banque Centrale (Banque des Etats de l'Afrique Centrale) majoré de deux (2) points.
Incidence sur l'exercice 2017	:	Au titre de l'exercice 2017, l'exécution de la convention de trésorerie n'a produit aucun intérêt.

- **CONVENTION DE COMPTE COURANT AVEC HEMLA AFRICA HOLDING**

Administrateur concerné	:	HEMLA AFRICA HOLDING AS représentée par Monsieur Knut SOVOLD et Monsieur Gerhard LUDVIGSEN.
Nature et objet	:	Convention de compte courant
Modalités et rémunération	:	Compte courant sur la base d'un taux d'intérêts correspondant au taux des avances de la Banque des Etats de l'Afrique Centrale (BEAC) augmenté de 2 points.
Incidence sur l'exercice 2017	:	Au titre de l'exercice 2017, USD 5 792 millions versés sur le compte de HEPC. Par ailleurs, aucun montant n'a été enregistré dans les charges et produits de l'exercice.

- **CONVENTION PORTANT SUR LES PRESTATIONS DE SERVICES REALISEES PAR MGI INTERNATIONAL**

Administrateur concerné	:	MGI INTERNATIONAL représentée par Monsieur Léon NGOMA BIKOUNGOU
Nature et objet	:	Convention de prestation de services
Modalité et rémunération	:	Comptes rémunérés à une commission fixe mensuelle de USD 30 000 de janvier à octobre 2017, puis USD 60 000 de novembre 2017 à décembre 2017, puis USD 75 000 à compter de janvier 2018.
Incidence sur l'exercice 2017	:	Au cours de l'exercice 2017, USD 457 milles ont été facturés.

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- **CONVENTION PORTANT SUR L'ASSISTANCE TECHNIQUE REALISEE PAR HEMLA AFRICA HOLDING**

Administrateur concerné : HEMLA AFRICA HOLDING AS représentée par Monsieur Knut SOVOLD et Monsieur Gerhard LUDVIGSEN.

Nature et objet : Convention d'assistance technique

Modalités et rémunération : Comptes rémunérés

Incidence sur l'exercice 2017 : Au cours de l'exercice clos le 31 décembre 2017, USD 2,195 millions ont été facturés.

3. CONVENTION NON PREALABLEMENT AUTORISEE ET EXECUTEE AU COURS DE L'EXERCICE ECOULE

- **CONVENTION RELATIVE A LA VENTE ET ACHAT DE PETROLE BRUT A HEMLA AFRICA HOLDING**

Administrateur concerné : HEMLA AFRICA HOLDING AS représentée par Monsieur Knut SOVOLD et Monsieur Gerhard LUDVIGSEN.

Nature et objet : Convention de vente de pétrole brut

Modalités et rémunération: Comptes rémunérés à 0.20 USD/bbl net de pétrole vendu.

Incidence sur l'exercice 2017 : Au cours de l'exercice clos le 31 décembre 2017, l'exécution de la convention relative à la vente et achat de pétrole brut n'a pas fait l'objet de marketing fees.

Le Commissaire aux Comptes
ERNST & YOUNG
Agréé CEMAC n°SEC 062

Ernst & Young Congo

Ludovic NGATSE
Expert-Comptable Agréé CEMAC n°EC 146
Associé

Pointe-Noire, le 24 Juillet 2018

HEMLA EP CONGO S.A. .

INDEPENDENT AUDITOR REPORT

AND FINANCIAL STATEMENTS

FOR THE YEAR ENDED 31 DECEMBER 2017

HEMLA EXPLORATION PRODUCTION CONGO S.A.
INDEPENDENT AUDITOR REPORT AND FINANCIAL STATEMENTS
FOR THE YEAR ENDED 31 DECEMBER 2017

CONTENTS PAGE

REPORT OF THE INDEPENDENT AUDITORS
TO THE BOARD OF DIRECTORS OF HEMLA EP CONGO

NDEPENDENT AUDITORS' REPORT TO THE DIRECTORS OF HEMLA EP CONGO

Opinion

As requested we have audited the financial statements of HEMLA EP Congo which comprise the statement of financial position as at December 2017 and the statement of comprehensive income, statement of changes in shareholders' equity and statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information, as set out on pages xx to xx.

In our opinion, the financial statements give a true and fair view of the financial position of the Company as at 31 December 2017, and of its financial performance and cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRSs) as issued by the IASB.

Basis for Opinion

We conducted our audit in accordance with International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Company in accordance with the International Ethics Standards Board for Accountants' Code of Ethics for Professional Accountants (IESBA Code) together with the ethical requirements that are relevant to our audit of the financial statements, and we have fulfilled our other ethical responsibilities in accordance with these requirements and the IESBA Code. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRSs, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are 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 ISAs 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 these financial statements.

As part of an audit in accordance with ISAs, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Other matter

HEMLA EP Congo Company has prepared a separate set of financial statements for the year ended December 31, 2017 in accordance of OHADA gaap on which we issued a separate auditor's report to the shareholders of HEMLA EP Congo Company dated July 24, 2018

Ludovic Ngatse
Ernst & Young Congo
March xx, 2019

HEMLA EXPLORATION PRODUCTION CONGO
STATEMENT OF COMPREHENSIVE INCOME
FOR THE YEAR ENDED 31 DECEMBER 2017

For the year ended December 31 *(in thousands of US dollars)*	Notes	2017
Sales	3	**68 351**
Cost of sales	4	**(26 241)**
Gross margin		**42 110**
General and administrative expenses	5	**(7 292)**
Operating profit		**34 818**
Finance expense	6	**(878)**
Foreign exchange losses	7	**(140)**
Profit before income tax		**33 801**
Current income tax	8	**(22 621)**
Deferred income tax	8	**-**
Loss for the period from continuing operations		**11 180**
Loss for the year from discountinued operations		
Profit for the period		**11 180**
Other comprehensive items		
Exchange differences on translating foreign operations		**-**
Comprehensive profit for the period		**11 180**
Earning per share - Basic and diluted		**0,11**

HEMLA EXPLORATION PRODUCTION CONGO
STATEMENT OF FINANCIAL POSITION
AS AT 31 DECEMBER 2017

As at *(in thousands of US dollars)*	Notes	December 31, 2017
ASSETS		
Non-current assets		
Intangible assets	9	**6 451**
Property, plant and equipment	10	**10 853**
		17304
Current assets		
Inventories	11	**2 369**
Trade and other receivables	12	**9 687**
Deposits and prepayments	13	**48**
Cash and cash equivalents	14	**5 837**
		17 941
Total assets		**35 245**
LIABILITIES		
Current liabilities		
Trade and other payables	15	**9 793**
Income Tax	8	**-**
		9 793
Non-current liabilities		
Provision for environmental restoration	16	**12 672**
		12 672
Total liabilities		**22 465**
EQUITY ATTRIBUTABLE TO SHAREHOLDERS		
Share capital	17	**1 600**
Accumulated Benefit		
Profit for the year		**11 180**
Total equity		**12 780**
Total liabilities and equity		**35 245**

HEMLA EXPLORATION PRODUCTION CONGO
STATEMENT OF CHANGES IN EQUITY
FOR THE YEAR ENDED 31 DECEMBER 2017

For the year ended December 31 *(in thousands of US dollars)*	**Note**	**Issued Capital**	**Accumulated profit**	**Total**
As at 01 January 2017	18	1 600		**1 600**
Profit for the year			11 180	**11 180**
As at 31 December 2017		1 600	11 180	12 780

HEMLA EXPLORATION PRODUCTION CONGO
STATEMENT OF CASH FLOWS
FOR THE YEAR ENDED 31 DECEMBER 2017

For the year ended December 31 *(in thousands of US dollars)*	Notes	2017
Cash flows from operating activities		
Profit for the period		**11 180**
Adjustments for:		
Depletion, depreciation and amortization	4 ,9 & 10	**2 511**
Finance expense	6	**773**
(Increase) / decrease in trade and other receivables	12	**(9 649)**
(Increase) / decrease in inventories	11	**(2 369)**
Decrease in deposit and prepayments	13	**(48)**
(Decrease) / increase in trade and other payables	15	**9 971**
Income tax paid	8	**-**
Net cash flow from operating activities		**12 154**
Cash flows from investing activities		
Payments for property, plant and equipment	10	**(535)**
Payments for Intangible assets	9	**(7 382)**
Net cash flow in investing activities		**(7 017)**
Cash flows from financing activities		
Proceeds from shareholder Equity	**17**	**1 600**
Net cash flow from financing activities		**1 600**
Effect of exchange rate fluctuations		**-**
(Decrease) / Increase in cash and cash equivalents		**5 837**
Cash and cash equivalents - beginning of period		
Cash and cash equivalents - end of period		**5 837**

1. CORPORATE INFORMATION

HEMLA EP CONGO ("HEPCO") SA is a limited liability Company incorporated in 29 December 2016 and located 2ème étage, Immeuble Tangu Center, BP 2722 Centre-Ville Pointe-Noire- Republic of Congo in accordance with OHADA business law. The company was registered in the commercial registry under registration number CG PNR 16 B 1414. The principal place of business is in Republic of Congo. . The Company's principal activities are exploration and production in the Republic of Congo offshore PSA area. HEPCO has 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 maned collectively "PNGF Sud".

The Company is subsidiary of HEMLA AFRICA HOLDING AS Norway ("HAH") which owns 72% of the shareholding, in addition to that 2.25% shares are held by the Chairman of the Company, Eyas Alhomouz are also assigned to HAH, hence making the effective ownership of HAH 74.25%HAH is in turn owned by PetroNor E&P Ltd. Cyprus for 70,707%. PetroNor E&P Ltd is incorporated in Cyprus. PetroNor E&P Ltd. is owned 50% by Petromal – Sole Proprietorship LLC UAE and 50% by Nor Energy AS Norway, both are the ultimate holding companies.

2. ACCOUNTING POLICIES

2.1 Basis of preparation

The financial statements have been prepared on a historical cost basis with the exception of items measured at fair value as indicated in the accounting policies below. The financial statements are presented in Dollars United States (USD) unless otherwise specified.

The FY 2017 is the first year of the company. For this period related to the year ended 31 December 2017, the company prepared its financial statements in accordance with OHADA gaap (Local GAAP). These financial statements for the year ended 31 December 2017 are the first the company has prepared in accordance with IFRS.

Refer to Note 2.4 for information on how the company adopted IFRS.

Statement of Compliance

The financial statements of the Company have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

2.2 Significant accounting judgements and estimates

The preparation of the financial statement requires the use of estimates and assumptions that affect the assets, liabilities, revenues and expenses reported in the financial statements including discussion and disclosure of contingent liabilities. Estimates made are based on complex or subjective judgments and past experience of other assumptions deemed reasonable in consideration of the information available at the time. The accounting policies and areas that require the most significant judgments and estimates to be used in the preparation of the Financial Statements are in relation to the accounting for oil and natural gas activities, specifically in the determination of unproved and proved developed reserves, impairment of fixed assets, intangible assets and goodwill, asset retirement obligations.

2.2.1 Estimates and assumptions

The preparation of the financial statements in conformity with IFRS as issued by the IASB requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities and contingent liabilities at the date of the consolidated financial statements and reported amounts of revenues and expenses during the reporting period. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However, actual outcomes can differ from these estimates.

In particular, significant areas of estimation uncertainty considered by management in preparing the financial statements are as follows:

2. ACCOUNTING POLICIES (Continued)

2.2 Significant accounting judgements and estimates (continued)

(i) Hydrocarbon reserve and resource estimates

Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from the company's oil and gas properties. The company 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 reserves reporting is normally done by independent reserves auditors.

2.2.2 Judgements

In the process of applying the company's accounting policies, the directors have made the following judgments, apart from those involving estimates, which have the most significant effect on the amounts recognised in the consolidated financial statements:

(i) Impairment indicators

The company assesses each cash-generating unit annually to determine whether an indication of impairment exists. When an indication of impairment exists, a formal estimate of the recoverable amount is made. The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell, or if relevant, a combination of these two models. These calculations require the use of estimates and assumptions <u>such as long-term oil prices (considering current and historical prices, price trends and related factors), discount rates, operating costs, future capital requirements, decommissioning costs, exploration potential, reserves and operating performance (which includes production and sales volumes)</u>. It is reasonably possible that the oil price assumption may change which may then impact the estimated life of the field and may then require a material adjustment to the carrying value of tangible assets. The company monitors internal and external indicators of impairment relating to its tangible and intangible assets.

The Net Present value (NPV) is based on the Competent Persons Report made by AGR-TRACS which are an international expert on reserves.

(ii) Technical risk in development of oil and gas fields

The development of the oil and gas fields, in which the company has an ownership, is associated with significant technical risk and uncertainty with regards to timing of additional production from new development activities. Risks include, but are not limited to, cost overruns, production disruptions as well as delays compared to initial plans laid out by the operator. Some of the most important risk factors are related to the determination of reserves, the recoverability of reserves, and the planning of a cost efficient and suitable production method. There are also technical risks present in the production phase that may cause cost overruns, failed investment and destruction of wells and reservoirs. Judgements have been made after taking into account information available to management and factors in unknown uncertainties as of the date of the balance sheet.

2. ACCOUNTING POLICIES (Continued)

2.2 Significant accounting judgements and estimates (continued)

(iii) Asset retirement obligations

Asset retirement costs will be incurred by the company at the end of the operating life of some of the company's facilities and properties. The company assesses its retirement obligation at each reporting date. The ultimate asset retirement 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 asset retirement obligation. 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 asset retirement costs required.

(iv) Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

2.3 Summary of significant accounting policies

Interests in joint arrangements

A joint arrangement is an arrangement over which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities (being those that significantly affect the returns of the arrangement) require unanimous consent of the parties sharing control.

Joint operations

A joint operation is a type of joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities, relating to the arrangement. In relation to its interests in joint operations, 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
- Expenses, including its share of any expenses incurred jointly.

Foreign currencies

The functional and presentation currencies of the company is US Dollars as the majority of its assets and transactions are US Dollar denominated.

The financial statements are presented in US dollars, as per the law, even if the local currency is XAF (CFA Franc BEAC).

Transactions denominated in a foreign currency are converted to US Dollars at rates ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies have been translated at the rates ruling at the reporting date. The resulting exchange gains or losses are recognised in profit and loss in the statement of comprehensive income.

2. ACCOUNTING POLICIES (Continued)

2.3 Significant accounting policies (continued)

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

Developed oil and gas reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet starter producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reason. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cos of drilling a new well.

Possible reserves

Possible reserves are those additional reserves that are less certain to be recovered that probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (Proved Oil and gas reserves a.III) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil and gas based on reservoir fluid properties and pressure gradient interpretations.

2. ACCOUNTING POLICIES (Continued)

2.3 Significant accounting policies (continued)

Probable reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(Possible reserves)(iv) and (a)(Possible reserves)(vi) of this section.

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

2. ACCOUNTING POLICIES (Continued)

2.3 Significant accounting policies (continued)

Reserves

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

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations)

Property, plant and equipment

(i) Oil & gas production assets

Development and production assets are accumulated on a cash-generating unit basis and represent the cost of developing the commercial reserves discovered and bringing them into production.

This include also Asset retirement costs which will be incurred by the company at the end of the operating life of some of the company's facilities and properties.

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.

(ii) Depreciation/amortisation

Oil and gas properties are depreciated or amortised using the unit-of-production method. Unit-of production rates are based on proved developed producing, 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.

The proved developed producing reserves are assessed by Netherlands, Sewell & Associates Inc (NSA) located in Texas (USA). NSA is independent reserves auditors

(iii) Impairment

An impairment review is carried out at each year end in accordance with International Accounting Standard (IAS) 36 – "Impairment of Assets". This review is based on assessments of the future net cash flows for each field calculated by utilising the company's estimate of proved reserves at year end, together with the company's estimates of future oil prices, future capital and operating costs and future decommissioning costs, required for recovering these remaining proved reserves. The calculations are performed based on the Competent Persons Report made by AGR-TRACS which are an international expert on reserves and using year-end exchange rates and a discount and inflation rate are. The discount rate of 12% and the inflation of 2% is used based on recommendation from our financial advisors (Arctic Securities & Pareto Securities) to be comparable with general NPV calculations for E&P in Africa in discussions with banks for financing / lending purposes. The discount range proposed is 8%-12% but we use the high end to be prudent. Reversals of previously recorded impairment are recognised only if supported by permanent changes in estimates utilised in the impairment review process.

2. ACCOUNTING POLICIES (Continued)
2.3 Significant accounting policies (continued)

The non-oil & gas PPE, mainly computer and vehicles, are depreciated on a straight-line basis over their useful lives (5 years - 20%)

Intangible assets

Intangible assets acquired separately are measured on initial recognition at cost. Following initial recognition, intangible assets are carried at cost less any accumulated amortisation and accumulated impairment losses, if any.

Intangible assets acquired in connection with a right to produce in an existing area are capitalised and amortized using the unit of production method on annual basis.

Financial assets

Initial recognition and measurement
Financial assets are classified, at initial recognition, as financial assets at fair value through profit or loss, loans and receivables, held-to-maturity investments, restricted cash, available-for-sale (AFS) financial assets, or derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial assets are recognised initially at fair value plus, in the case of financial assets not recorded at fair value through profit or loss, transaction costs that are attributable to the acquisition of the financial asset.

Purchases or sales of financial assets that require delivery of assets in a timeframe established by regulation or convention in the market place (regular way trades) are recognised on the trade date, i.e., the date at which the company commits to purchase or sell the asset.

The company's financial assets include cash and cash equivalents, Deposits and prepayments and certain trade and other receivables.

Subsequent measurement
For purposes of subsequent measurement financial assets are classified into four categories:
- Financial assets at fair value through profit or loss
- Trade and other receivables
- Held-to-maturity investments – the company has no held-to-maturity investments
- AFS financial investments – the company has no AFS financial assets

Financial assets at fair value through profit or loss
Financial assets at fair value through profit or loss include financial assets held for trading and financial assets designated upon initial recognition at fair value through profit or loss. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives, are also classified as held for trading unless they are designated as effective hedging instruments, as defined by IAS 39. Financial assets at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value presented as finance costs (negative changes in fair value) or finance revenue (positive net changes in fair value) in the statement of comprehensive income. The company has not designated any financial assets at fair value through profit or loss.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not held for trading or designated at fair value though profit or loss. These embedded derivatives are measured at fair value, with changes in fair value recognised in the statement of profit or loss and other comprehensive income. Reassessment occurs only if there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required or there is a reclassification of a financial asset out of the fair value through profit or loss category. The company has no embedded derivatives as of December 31, 2017.

2. ACCOUNTING POLICIES (Continued)

2.3 Significant accounting policies (continued)

Trade and other receivables

This category is most relevant to the company. Trade and other receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, such financial assets are subsequently measured at amortised cost using the effective interest rate method, less impairment. 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 effective interest rate. The effective interest rate amortisation is included in finance income in the statement of profit or loss and other comprehensive income. The losses arising from impairment are recognised in the statement of profit or loss and other comprehensive income in finance costs for loans and in cost of sales or other operating expenses for receivables.

Cash and cash equivalents

Cash and cash equivalents includes cash at hand, and deposits held on call with banks. Cash balances in current accounts, short-term deposits and placement with maturity of six months or less in highly liquid investments are classified as cash and cash equivalents.

Impairment of financial assets

The company assesses at each reporting date whether a financial asset or group of financial assets are impaired.

Financial liabilities

Initial recognition and measurement

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate.

All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The company's financial liabilities include trade and other payables.

Subsequent measurement

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

Trade payables

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

Asset retirement obligation

An asset retirement 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 asset retirement, discounted to its present value. Changes in the estimated timing of asset retirement or asset retirement 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 asset retirement provision is included as a finance cost.

2. ACCOUNTING POLICIES (Continued)

2.3 Significant accounting policies (continued)

Income taxes

Production-sharing arrangements

According to the production-sharing arrangement (PSA) in the licenses, 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 company. This amount will be paid directly by the government on behalf of company to the appropriate tax authorities by the operator in kind or barrels. This is called tax oil

The income tax expense

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

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. However, as there is no income tax calculation to be made using the tax rates, no deferred tax assets or liabilities has been assessed and booked. .

Revenue recognition

Revenue from petroleum products

Revenue from the sale of petroleum products is recognized as income using the **"entitlement method" or sales method?.** Under this method (entitlement method), revenue is recorded based on the asset's proportionate share of total crude, gas and NGL produced from the affected fields. Revenue is stated net of royalties.

Under sales method, the revenue is presented gross of royalties and tax oil. The company has used the sales method.

Inventories

Inventories are stated at the lower of cost and net realisable value. Costs comprise of direct materials and, where applicable, direct labour costs and those overheads that have been incurred in bringing the inventories to their present location and condition. Net realisable value represents the estimated selling price less all estimated costs of completion and costs to be incurred in marketing, selling and distribution. Provision is made for obsolete, slow-moving or defective items where appropriate.

Related party transactions

The company has complied with the requirements of International Accounting Standard ("IAS") 24 – Related party transactions in these financial statements. Transactions with related parties are disclosed in each relevant note.

Contingencies

Contingent liabilities

If it becomes probable that an outflow of future economic benefits will be required for an item previously dealt with as a contingent liability, a provision is recognised in the financial statements of the period in which the change in probability occurs.

2. ACCOUNTING POLICIES (Continued)

2.3 Significant accounting policies (continued)

Contingent assets

If it has become virtually certain that an inflow of economic benefits will arise, the asset and the related income are recognised in the financial statements of the period in which the change occurs. If an inflow of economic benefits has become probable, an entity discloses the contingent asset.

Employee benefits

Retirement benefit costs

The Company contributes to a statutory defined contribution pension scheme, the Caisse National de Sécurité Social (CNSS). Contributions are determined by local statute. The Company's CNSS contributions are charged to profit or loss in the period to which they relate. The company does not booked the employee benefits but the amount is not material as this is the first year of the company.

Operating leases

Leases where substantially all the rewards and risks of ownership of assets remain with the lessor are accounted for as operating leases. Where the company is the lessee, rentals payable under operating leases are charged to the income statement on a straight-line basis over the lease terms.

2.4 First time adoption

These financial statements, for the year ended 31 December 2017, are the first the company has prepared in accordance with IFRS. The year ended 31 December 2017 is the first year of the company. For the same period ended 31 December 2017, the company prepared its financial statements in accordance with local generally accepted accounting principle (Local GAAP).
Accordingly, the company has prepared financial statements that comply with IFRS applicable as at 31 December 2017 without comparative period data, as described in the summary of significant accounting policies.
In preparing the financial statements, the company's date of transition to IFRS is 1 January 2017.

This note explains the principal adjustments made by the company in restating its Local GAAP financial statements for the year ended 31 December 2015.

Exemptions applied
IFRS 1 allows first-time adopters certain exemptions from the retrospective application of certain requirements under IFRS.
No exemption has been applied.

Estimates
The estimates at 31 December 2017 are consistent with those made for the same dates
in accordance with Local GAAP (after adjustments to reflect any differences in accounting policies) apart from the asset retirement obligation.

2. ACCOUNTING POLICIES (Continued)

2.4 First time adoption (continued)

(i) **Group reconciliation of equity as at 31 December 2017**

As at *(in thousands of US dollars)*	*OHADA GAAP*	*Adjustment Stock Oil 2017 IFRS (Note A)*	*Adjustment of ARO booking by OHADA (Note B)*	*ARO NPV Initial (Note C)*	*Accretion on ARO YTD 2017 (Note D)*	*Depreciation ARO Asset 2017 (Note E)*	*Foreign exchange (Note F)*	*Reclass Prepaid & Prepayment (Note G)*	*Balance IFRS*
ASSETS									
Non-current assets									
Intangibles assets	6 451								6 451
Property, plant and equipment	460			11 899		-1 505			10 853
Financial asset	31							-31	0
									17 305
Current assets									
Inventories	3 447	-1 078							2 369
Trade and other receivables	9 704						-38	-17	9 649
Deposits and prepayments	-							48	48
Cash and cash equivalents	5 837								5 837
									17 903
Total assets	**25 899**	**-1 078**	**-**	**11 899**	**-**	**-1 505**	**-38**		**35 207**
LIABILITIES									
Current liabilities									
Trade and other payables	15 488		-5 517				-216		9 755
									9 755
Non-current liabilities									
Deferred tax liabilities									-
Provision for environmental restoration				11 899	773				12 672
Total liabilities	**15 488**	**-**	**-5 517**	**11 899**	**773**	**-**	**-216**		**22 428**
EQUITY ATTRIBUTABLE TO SHAREHOLDERS									
Share capital	1 600								1 600
Profit / (loss) for the year	8 842	-1 078	5 517		-773	-1 505	178		11 180
Total equity	**10 442**	**-1 078**	**5 517**	**-**	**-773**	**-1 505**	**178**		**12 780**
Total liabilities and equity	**25 930**	**-1 078**	**-**	**11 899**	**-**	**-1 505**	**-38**		**35 208**

2. ACCOUNTING POLICIES (Continued)

2.4 First time adoption (continued)

(ii) Group reconciliation of total comprehensive income for the year ended 31 December 2017

For the year ended December 31							
(in thousands oB US dollars)	*OHADA GAAP*	*Adjustment Stock Oil 2017 IFRS (Note A)*	*Adjustment of ARO booking by OHADA (Note B)*	*Accretion ARO YTD 2017 (Note D)*	*Depreciation ARO Asset 2017 (Note E)*	*Foreign exchange (Note F)*	*Balance IFRS*
Sales	68 351						68 351
Cost of sales	(29 174)	(1 078)	5 517		(1 505)		(26 241)
Gross margin	**39 177**	**(1 078)**	**5 517**	**-**	**(1 505)**	**-**	**42 110**
General and administrative expenses	(7 292)						(7 292)
Operating profit / (loss)	**31 884**	**(1 078)**	**5 517**	**-**	**(1 505)**	**-**	**34 818**
Finance expense	(105)			(773)			(878)
Foreign exchange gain (loss)	(317)					178	(140)
Profit / (loss) before income tax	**31 463**	**(1 078)**	**5 517**	**(773)**	**(1 505)**	**178**	**33 801**
Current income tax	(22 621)						(22 621)
Deferred income tax							
Loss for the period from continuing operations	**8 842**	**(1 078)**	**5 517**	**(773)**	**(1 505)**	**178**	**11 180**
Loss for the year from discountinued operations	**-**						**-**
Profit / (loss) for the period	**8 842**	**(1 078)**	**5 517**	**(773)**	**(1 505)**	**178**	**11 180**
Other comprehensive profit / (loss) (items that may be reclassified subsequently to profit or (loss))							
Exchange differences on translating foreign operations							
Comprehensive profit / (loss) for the period	**8 842**	**(1 078)**	**5 517**	**(773)**	**(1 505)**	**178**	**11 180**

(iii) Notes to the reconciliation of equity and total comprehensive income for the year ended 31 December 2017

Note A: In local gaap, the crude oil (underlifting) is valued at market price. For the purposes of IFRS, it is valuated at lower of cost and net realizable value (NRV). As the cost is lower than the NRV, the crude oil has been assessed at cost. The adjustment represents the difference between market value and cost amount

Note B: In local gaap, part of asset retirement obligation has been requested to put in bank accounts but this has been booked wrongly as expense. Therefore, the cost booked in local gaap has been reversed.

Note C: In connexion with the note B, in IFRS, all the ARO has been discounted at the beginning of January 2017 and booked as cost (part of O&G PPE's which is depreciated using unit of product method.

Note D: In connexion with the note C, this is the accretion of ARO provision which is not booked in local gaap but only in IFRS. This is booked to increase the provision (liabilities) and as finance expenses

Note E: In connexion the note B, this is the depreciation of ARO asset using unit of product method

2. ACCOUNTING POLICIES (Continued)

2.4 First time adoption (continued)

Note F: In local unrealized exchange gains are not recognised in profit & loss and the unrealised exchanges losses are recognised in profit & loss through a depreciation. In compliance with IAS 21, we cancelled all the entries booked in compliance with local gaap and recognised in profit & loss, all the unrealized exchanges losses /gains.

Note G: we have two adjustments: (i) The rental deposit, USD 31K booked as long-term finance asset in local gaap. As the maturity of the rent is less than one year at the end of the FY 2017, this has been reclassified in current assets in compliance with IFRS; (ii) the January 18's rent prepaid for USD 17K and booked in local gaap as other receivables. In IFRS, the prepaid rent has been reclassified as prepayments.

2.5 Standards issued but not yet effective

The standards and interpretations that are issued, but not yet effective, up to the date of issuance of the Group's financial statements are disclosed below. The company intends to adopt these standards, if applicable, when they become effective.

- IFRS 2 Classification and Measurement of Share-based Payment Transactions — Amendments to IFRS 2
- Amendments to IFRS 4: Applying IFRS 9 Financial Instruments with IFRS 4 Insurance Contracts
- IFRS 9 Financial Instruments
- Amendments to IFRS 10 and IAS 28: Sale or Contribution of Assets between an Investor and its Associate or Joint Venture
- IFRS 15 Revenue from Contracts with Customers
- IFRS 16 Leases
- IFRS 17 Insurance Contracts
- Amendments to IAS 40: Transfers of Investment Property
- IFRS 22 Foreign Currency Transactions and Advance Consideration
- IFRIC 23 Uncertainty over Income Tax Treatments.

Annual Improvements 2014-2016 Cycle

- IFRS 1 First-time adoption of International Financial Reporting Standards – Deletion of short-term exemptions for first time adopters
- IAS 28 Investments in Associates and Joint Ventures – Clarification that measuring investees at fair value through profit or loss is an investment-by-investment choice
- IFRS 3 Business Combinations - Previously held interests in a joint operation
- IFRS 11 Joint Arrangements - Previously held interests in a joint operation
- IAS 12 Income Taxes - Income tax consequences of payments on financial instruments classified as equity
- IAS 23 Borrowing Costs - Borrowing costs eligible for capitalization

Management intends to adopt these standards and amendments, if applicable, when they become effective. Management has performed initial assessment of the impact of IFRS 9 and IFRS 15 on its financial statements. Management believes that the initial application of these standards will not have a significant impact on the financial statements.

3.Sales

KUSD	2017
Oil Sales Net from Tax and Royalties	35 316
Assignement of Tax Oil	22 621
Assignement of Royalties	10 415
Total	**68 351**

Below the detail of the lifting made during the year:

Date	Description	Quantity	Price	Revenue (KUSD)
30/06/2017	Oil Saled on the interim periode	290 094	50,25	14 576
28/11/2017	Oil Sale Djeno Melange	300 000	60,74	18 221
28/11/2017	Oil Sale Nkossa Blend	40 000	62,97	2 519
2017	**Total**	**630 094**	**56,05**	**35 316**

4.Cost of sales

KUSD	2017
Depletion and depreciation of oil and gas assets	2 511
Royalties	10 415
PNGF sud ‘s opex	14 175
Other Operating costs	1 509
Variation of net realisable value of oil inventories	(2 369)
Cost of Sales	**26 241**

5. General and administrative expenses

KUSD	2017
Employee benefit expense	(944)
Travel and Accomodation fees	(800)
Donations	(475)
Rental fees	(157)
Consulting fees and external services	(199)
Other general and administration expenses	(4 718)
General and administrative expenses	**(7 292)**

6. Finance expenses

KUSD	- 2017
Accretion of environmental restoration provision	(773)
Interest on cash in bank	(105)
Finance expense	**(878)**

The finance expenses are mainly related to asset retirement cost accretion (refer to note 16 for more detail of the calculation parameters).

7. Foreign exchanges

KUSD	2017
Foreign Exchange Loss	(140)
Foreign exchange	**(140)**

8. Tax expense analysis

KUSD	2017
Current income tax expense	**(22 621)**
Deferred income tax income / (expense)	
Origination and reversal of temporary differences	-
	-
Total income tax expense	**(22 621)**

Income tax was paid in barrels of Oil at source as per PSA.

9. Intangibles assets

KUSD	Oil and Gas Licences	Other intangible asset	Intagible asset
Cost			
Balance, beginning of the period	-	-	-
Additions	7 382		7 382
Disposals	-	-	-
Balance, end of the period	**7 382**	**-**	**7 382**
Depletion, depreciation and impairment losses			
Balance, beginning of the period	-	-	-
Depletion and depreciation	931	-	931
Impairments	-	-	-
Disposals	-	-	-
Balance, end of the period	**931**	**-**	**931**
Net book value	**6 451**	**-**	**6 451**

Below the detail of cost

	USD
Tender costs	300 000
Entry bonus	1 200 000
Signature Bonus	5 882 000
Total	7 382 000

10. Property Plant Equipment

KUSD	Oil and Gas properties	Other plant and equipment	Property, plant and equipment
Cost			
Balance, beginning of the period	-	-	-
Additions	12 425	9	12 433
Disposals	-	-	-
Balance, end of the period	**12 425**	**9**	**12 433**
Depletion, depreciation and impairment losses			
Balance, beginning of the period	-	-	-
Depletion and depreciation	1 572	9	1 580
Impairments	-	-	-
Disposals	-	-	-
Balance, end of the period	**1 572**	**9**	**1 580**
Net book value	**10 853**	**-**	**10 853**

The cost is mainly related to asset retirement obligation booked for USD 11 899K and O&G capex for USD 500K.

11. Inventories

KUSD	**2017**
Crude oil	**1 856**
Materials and supplies	**513**
Total	**2 369**

	-
	déc-17
Crude Oil (KUSD)	1 856
Bbls	44 939
Production cost per bbl	41,30

Materials and supplies

KUSD	**2017**
Gross value of material and supplies	
Balance, beginning of the year	**-**
Movements	**513**
Balance, end of the year	**513**
Depreciation and impairments	
Balance, beginning of the year	**-**
Impairment	**-**
Balance, end of the year	**-**
Net book value	**513**

12. Trade and other receivables

KUSD	**2017**
Trade receivables	**3 419**
Dues from related parties	**6 134**
Others receivables	**96**
Total	**9 649**

The receivables are mostly related to the related parties and are collectible in less than one year.

The company considers that the carrying amount of trade debtors and other debtors approximates their fair value. No allowance for doubtful debts has been recorded for Trade and other receivables,

13. Prepayments

The prepayments are related to the rent paid in advance for USD 17K and rent deposit for USD 31K.

14. Cash and cash equivalents

KUSD	2017
Local Banks	5 746
Petty Cash	91
Other Cash and cash equivalents	-
Total	5 837

Cash in bank does not bear an interest.

15. Trade payables

KUSD	2017
Trade payables	4 829
Taxes payables	3 398
Accruals	1 471
Dues to employees	56
Other payables	216
Total	9 971

The trade payables are non-interest-bearing and are normally settled on 30-day to 120-day terms.

16. Provision for environmental restoration

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 depend on the rate the reserves of the field are depleted. However, based on the existing production profile of the PNGF SUD field and the size of the reserves, it is expected that expenditure on retirement is likely to be after more than ten years. The current bases for the provision are a discount rate of 6.5% and an inflation rate of 1.6%. The 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:

KUSD	2017
Balance, beginning of period / year	-
Provision for environmental restoration	11 899
Accretion	773
Balance, end of period / year	12 672

17. Share capital

	Period ended December 31, 2017	
	Number	Amount
Balance, beginning of period/year	100 000	1 600 000
Balance, end of period/year	100 000	1 600 000

18. RELATED PARTIES TRANSACTIONS AND BALANCES

The Company is a subsidiary of HAH which is owns by Petronor and AS Norway energy. The following provide the total amount of transactions that have been entered into with related parties and outstanding balances for the relevant financial year:

	Sales to related parties (1)	Purchases from related parties (2)	Amounts owed by related parties (3)	Receivables from related parties (4)	Interest received	Interest paid
HAH	20 740	2 195	5 792	3 419	-	-
MGI	-	457	-	-	-	-
Other group subsidiaries	-	-	342	-	-	-

(1)This is related to sales of crude oil to HAH
(2)This is related to technical assistance from NGI and HAH, both the company's shareholders.
(3)This is related to Miscellaneous Cash transactions between HEPCO and HAH, as HAH is receiving for the proceed from sales and pay for invoices and JIB from offshore bank account on behalf of HEPCO; those amounts are already paid totally in 2018
(4)This is related to amount due on the last invoice of oil sale, this amount is already paid on January 2018.

Key Management compensation

Compensation of key management personnel	2017
Short-term employee benefits	623
Post-employment pension and medical benefits	-
Termination benefits	-
Share-based payment transactions	-
Total compensation paid to key management personnel	623

The key compensation has been paid to the three Managers of the company.

Below, the list of key management personnel:

- Valentin TCHIBOTA GOMA: Deputy General Manager
- Wilfrid NGOMA MBOUKOU: Finance and Administrative Manager
- Paul Marie TATY MOUANDA : Technical Manager

19. FINANCIAL RISK MANAGEMENT AND POLICIES

The Company's principal financial liabilities comprise trade and other payables. The main purpose of these financial liabilities is to raise finance for the Company's operations. The Company has various financial assets such as trade and other receivables, other receivables and cash and short-term deposits, which arise directly from its operations.

The main risks that could adversely affect the company'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, as well capital management, which are summarized below.

Credit Risk

The Company's credit risk arises from counterparty of derivative financial instruments which fail to meet his/its contractual obligations as well as credit exposures to trade and other receivables. This risk originates principally from the account receivables. However, the credit risk is mitigated as the trade receivables and other receivables, shown in the financial position are fully linked to related parties (refer to note 12).

Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the company's business activities may not be available or the Company will not be able to meet its financial obligations as they fall due. The company has access to a wide range of funding through the capital markets and banks, The company believes it has access to sufficient funding to meet currently foreseeable borrowing requirements.

HAH, undertake to provide the company, with the funding and/or other support needed to make it possible for HEPCO to meet its financial obligations. In addition, shall exercise their rights as indirect majority shareholders of HEPCO in such a manner so as to support it in accordance with the principles of sound business practice in the fulfillment of its financial obligations.

Effective management of the liquidity risk has the objective of ensuring the availability of adequate funding to meet short term requirements and due obligations as well as the objective of ensuring a sufficient level of flexibility in order to fund the development plans of the company's businesses.

The trade and other payables at the end of FY 17 are payables within 3 months and the company have sufficient fund (cash and cash equivalent and the trade receivables other receivables) to meet their maturity.

Interest rate risk

Variations in interest rates affect the market value of financial assets and liabilities of the company
The company is not exposed to interest rate risk as it has no financial debts and no investments in interest bearing instruments.

Foreign currency risk

As most of the payments are made in USD the Company's exposure to other currencies is low and limited to local transactions paid in XAF (salary, rent, etc). It has not used any forward contracts, currency borrowings or other means to hedge its exposure.

The Company has foreign currency exposure to the insignificant part of trade payables and other receivables which are denominated XAF. At the end of the FY 2017, the unrealized exchanges losses amounts to **USD 177K** which is not significant. The sensitivity at the reporting date to a reasonably possible change in the USD exchange rate, with all other variables held constant, of the Company's profit before tax (due to changes in the fair value of monetary assets and liabilities) and the Company's owners' equity will not be significant.

19. FINANCIAL RISK MANAGEMENT AND POLICIES (continued)

Capital management

Capital includes equity attributable to the equity holders of the Company.

The primary objective of the Company's capital management is to ensure that it maintains a strong credit rating and healthy capital ratios in order to support its business and maximise shareholder value.

The Company manages its capital structure and makes adjustments to it, in light of changes in economic conditions. To maintain or adjust the capital structure, the Company may adjust the dividend payment to shareholders, return capital to shareholders or issue new shares.

Since the creation of the company in December 2016, no changes was made in the objectives, policies or processes during the years ended 31 December 2017.

20. COMMITMENTS

(i) Operating leases commitments

The company leases certain of its office properties and sites under operating lease arrangements with lease terms ranging from one to three years. At each reporting date, the company had total future minimum lease payments under non-cancellable operating leases in respect of buildings, local network, civil and technical sites as follows:

KUSD	**December 2017**
Within one year	200
In the second to fifth years, inclusive (1)	480
	680

(1) This is related to new agreement signed during FY 18 for new HQ office.

(ii) Capital commitments

There is no capital commitment as the end of the FY 2017.

21. FINANCIAL INSTRUMENTS BY CATEGORY

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 trade and other payables.

The fair values of the Group's financial instruments are not materially different from their carrying amounts at the reporting date.

22. EVENTS AFTER THE REPORTING DATE

No audited financial statements have been prepared by the Company in respect of any period subsequent to 31 December 2017.

The following events have occurred since the closing date:

- Appointment of new CEO: This decision by the Board meeting of December 19, 2018 with effective date of Appointment January 2nd 2019.

22. EVENTS AFTER THE REPORTING DATE (Continued)

- New local accounting gaap effective since January 1, 2018
- Restructuring plan : As per the resolution of Board meetings of August 20, 2018 and November 10th , 2019, it is decided the restructuration of the company by changing the management team and the organization chart of the company Human resources, the objective is to have a small team with amelioration of efficiency the implementation of this restructuring plan began in December 2019 and is expected to take place in April 2019
- Appointment of New Directors of the company: The GM of August 7th, 2018 have appointed a new Directors team :
  - Eyas Alhomouz Randa, Chairman
  - Knut Sovold : Director
  - Gerhard Ludvegsen : Director
  - Khaled Jamel Ayoub : Director
  - Patrick Ntsibat : Director
  - Trond Kosveit : Director
  - Paul Ngoma Kionga : Director

APPENDIX C:

INDEPENDENT PRACTITIONER'S ASSURANCE REPORT ON THE PROCESS TO COMPILE PRO FORMA FINANCIAL INFORMATION

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INDEPENDENT PRACTITIONER'S ASSURANCE REPORT ON THE PROCESS TO COMPILE PRO FORMA FINANCIAL INFORMATION

Board of Directors

We have completed our assurance engagement to report on the process applied by African Petroleum Corporation Limited (the company) to compile the pro forma financial information, consisting of the pro forma statement of financial position at 31 December 2017, the pro forma statement of comprehensive income for the period ended 31 December 2017 as set out on pages 70-76 of the information memorandum issued by the company. The applicable criteria in accordance with which this process has been applied are specified in Annex II of Regulation (EC) 809/2004 described in Note 10.1.

The pro forma financial information has been compiled by management to illustrate the impact of the transaction set out in Note 10.1 on the company's financial position as at 31 December 2017 and its financial performance for the period then ended. As part of this process, information about the company's financial position and financial performance has been extracted from the company's financial statements for the period ended 31 December 2017, on which an audit has been published. Because of its nature, the pro forma financial information does not represent the company's actual financial position and financial performance.

Management's Responsibility for the Pro Forma Financial Information

Management of the company is responsible for applying the process to compile the pro forma financial information in accordance with the applicable criteria specified in Annex II of Regulation (EC) 809/2004 described in Note 10.1.

Practitioner's Responsibilities

Our responsibility is to express an opinion, as required by Annex II of Regulation (EC) 809/2004, about whether the process to compile the pro forma financial information has been applied by management in accordance with the applicable criteria. We are not responsible for updating or reissuing any reports or opinions on any financial information used in compiling the pro forma financial information. In addition, we have not performed an audit or review of the pro forma financial information and, accordingly, we do not express an opinion on the pro forma financial information.

We conducted our engagement in accordance with International Standard on Assurance Engagements (ISAE) 3420, *Assurance Reports on the Process to Compile Pro Forma Financial Information Included in a Prospectus*, issued by the International Auditing and Assurance Standards Board. This standard requires that we comply with ethical requirements and plan and perform our procedures to obtain reasonable assurance about whether the responsible party has applied the process to compile the pro forma financial information in accordance with the applicable criteria.

Our procedures included:

- Making inquiries of management regarding the process management has applied to compile the pro forma financial information;
- Evaluating whether management has used an appropriate source of the unadjusted financial information in compiling the pro forma financial information;
- Checking whether management has appropriately extracted the unadjusted financial information from the source documents;
- Evaluating whether management has compiled the pro forma financial information on a basis consistent with the company's financial reporting framework and its accounting policies under that framework and where there is a departure adequately disclosed this in the pro forma basis of preparation;
- Considering management's evidence supporting the pro forma adjustments and verifying these back to that supporting evidence;
- Determining whether the calculations within the pro forma financial information are arithmetically accurate; and
- Evaluating the overall presentation and disclosure of the pro forma financial information and related explanatory notes.

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

Opinion

In our opinion, the process to compile the pro forma financial information has, in all material respects, been applied in accordance with the applicable criteria and the pro forma financial information has been properly compiled on the basis stated.

BDO Audit (WA) Pty Ltd

BDO

Phillip Murdoch

Director

Perth, 27 March 2019

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