INFORMATION MEMORANDUM

in connection with the acquisition of

BP Norge AS by

Det norske oljeselskap ASA

(a public limited liability company incorporated under the laws of Norway)

The information contained in this information memorandum (the "**Information Memorandum**") relates to the acquisition of BP Norge AS ("**BP Norge**") (the "**Transaction**") by Det norske oljeselskap ASA, a public limited liability company existing under the laws of Norway (the "**Company**", and taken together with its subsidiaries, the "**Group**").

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 consideration shares to be issued in connection with the Transaction, cf. Section 7-5 no. 7 of the Norwegian Securities Trading Act. The Continuing Obligations apply in respect of companies with shares admitted to trading on Oslo Børs (the "**Oslo Stock Exchange**") and this Information Memorandum has been submitted to the Oslo Stock Exchange for inspection before it was published. This Information Memorandum is not a prospectus and has neither been inspected nor approved by the Norwegian Financial Supervisory Authority (Nw. *Finanstilsynet*) in accordance with the rules that apply to prospectuses.

On 10 June 2016, the Company entered into a transaction agreement with Amoco Norway Oil Company and BP Global Investments Ltd as sellers (the "**Sellers**"), in respect of the Transaction. The Company will acquire 100% of the shares in BP Norge against a cash consideration and issuance of new shares to Amoco Norway Oil Company and BP Global Investments Ltd. The Transaction will be considered by the shareholders of the Company at an Extraordinary General Meeting to be held on 15 September 2016.

This Information Memorandum does not constitute an offer or solicitation 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 3.

The date of this Information Memorandum is 9 September 2016.

IMPORTANT INFORMATION

The information contained herein is current as of the date hereof and subject to change, completion and amendment without notice. The publication and distribution of this Information Memorandum shall not under any circumstances create any implication that there has been no change in the affairs of the Group or that the information herein is correct as of any date subsequent to the date of this Information Memorandum. No person is authorised to give information or to make any representation in connection with the Transaction other than as contained in this Information Memorandum. 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 his or her own legal, business or tax advisor as to legal, business or tax advice. No due diligence has been made on the Company in connection with preparation of this Information Memorandum.

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, including, but not limited to, statements relating to the risks specific to the Group's businesses and the implementation of strategic initiatives, as well as other statements relating to the Group's future business development and economic performance. These forward-looking statements can be identified by the use of forward-looking terminology, including the terms "assumes", "projects", "forecasts", "estimates", "expects", "anticipates", "believes", "plans", "intends", "may", "might", "will", "would", "can", "could", "should" or, in each case, their negative, or other variations or comparable terminology. These forward-looking statements are not historic facts. They appear in a number of places throughout this Information Memorandum and include statements regarding the Company's intentions, beliefs or current expectations concerning, among other things, goals, objectives, financial condition and results of operations, liquidity, prospects, growth, strategies, impact of regulatory initiatives, capital resources, and the industry trends and developments. Readers are cautioned that forward-looking statements are not guarantees of future performance and that the actual financial condition, operating results and liquidity of the Group, and the development of the industries in which it operates, may differ materially from those made in or suggested by the forward-looking statements contained in this Information Memorandum. 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 certain factors that could adversely affect the business, financial condition, operating results, liquidity, performance and prospects of the Group. Readers are urged to read all sections of this Information Memorandum and, in particular, Section 1 "Risk Factors".

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.

This Information Memorandum shall be governed by and construed in accordance with Norwegian law. The courts of Norway, with Oslo as legal venue, shall have exclusive jurisdiction to settle any dispute which may arise out of or in connection with this Information Memorandum.

INFORMATION SOURCES FROM THIRD PARTIES

The information in this Information Memorandum that has been sourced from third parties has been accurately reproduced and as far as the Company is aware and able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

INFORMATION INCORPORATED BY REFERENCE

The Continuing Obligations allow the Company to incorporate by reference information in this Information Memorandum that has been previously filed with the Oslo Stock Exchange or the Norwegian Financial Supervisory Authority in other documents. The audited historical financial statements for the Group as of and for the years ended 31 December 2015, 2014 and 2013 (the "**Annual Financial Statements**"), the unaudited historical financial statements for the Group as of and for the six months ended 30 June 2016 and 2015 (the "**Interim Financial Statements**"), prepared in accordance with International Financial Reporting Standards as adopted by the European Union ("**IFRS**") and the audit reports in respect of the Annual Financial Statements have been incorporated as a part of this Information Memorandum; see Section 10 "Incorporation by Reference; Documents on Display". Accordingly, this Information Memorandum is to be read in conjunction with these documents.

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1. RISK FACTORS

*Holders of shares in the Company ("**Shares**") should consider the risks described below, as well as the other information in this Information Memorandum. These risks are not the only ones of relevance to the business of the Group. Additional risks and uncertainties not known at present or that is deemed immaterial may also impair the business, financial condition, operating results, liquidity, performance and prospects of the Group. The order in which the risks are presented below is not intended to provide an indication of the likelihood of their occurrence nor of their severity or significance. These risks should also be considered in connection with the cautionary statement regarding forward-looking information set forth on page 1 of this Information Memorandum.*

1.1 Risks Relating to the Transaction

The unaudited pro forma financial information included in this Information Memorandum has been prepared solely to show what the significant effects of the Transaction might have been had the Transaction occurred at an earlier date and does not purport to present the results of operations or financial condition of the Group, nor should it be used as the basis of projections of the results of operations or financial condition of the Group for any future period or date.

This Information Memorandum includes unaudited pro forma condensed consolidated financial information for the Group as of and for the year ended 31 December 2015. Although the unaudited pro forma financial information is based on estimates and assumptions based on current circumstances believed to be reasonable, actual results could have materially differed from those presented herein. There is a greater degree of uncertainty associated with pro forma figures than with actual reported results. The unaudited pro forma financial information has been prepared for illustrative purposes only and, because of its nature, addresses a hypothetical situation and, therefore, does not purport to present the results of operations of the Group as if the Transaction had occurred at the commencement of the period being presented, or the financial condition of the Group as of the date being presented, nor should it be used as the basis of projections of the results of operations for the Group for any future period or the financial condition of the Group for any date in the future.

Under the Transaction Agreement, consummation of the Transaction is conditional upon satisfaction of a number of conditions that are beyond the control of the Company; the Transaction may hence not be consummated and transaction costs will have been incurred for the Group regardless of whether the Transaction is consummated which could negatively affect the business, results of operation and financial condition of the Group.

Consummation of the Transaction is conditional upon satisfaction of a number of conditions, the satisfaction of which are beyond the control of the Company; see Section 4 "The Transaction". If the Transaction is not consummated, transaction costs, including costs of advisors and the use of key management personnel's time and attention, will have been incurred without the expected benefits and at the expense of other business opportunities.

In addition, there will be no realisation of any of the expected benefits of having completed the Transaction and failure to complete the Transaction could result in a negative perception by the stock market of the Company and result in a decline of the market value of the Company's shares.

If any of the above risks materialise, it could negatively affect the business, results of operation and financial condition of the Group.

The Company may not be able to successfully implement the expected benefits or achieve the anticipated synergies of the Transaction.

The Transaction involves the integration of the two companies that have previously operated independently. Achieving the benefits of the Transaction will depend in part upon meeting the challenges inherent in the successful combination and integration of business enterprises of the Company and BP Norge. There can be no assurance that the Company will meet these challenges and that such diversion will not negatively affect operations, or that the benefits expected from the Transaction will be realised. In addition, delays encountered in the transition process could have a material adverse effect on revenues, expenses, operating results and financial condition. There can be no assurance that the Company will actually achieve anticipated synergies or other benefits from the Transaction. Should any of these risks associated with acquisitions materialise, it could have a material adverse effect on the Group's business, financial condition and results of operations.

One of the key challenges is the integration of the IT-systems in the two companies, both with respect to hardware and software. The business is dependent of a well-functioning It-system for safe and effective operations.

The Company may encounter separation challenges as a consequence of the Transaction.

A pre-condition for a successful integration is a successful separation of BP Norge from BP. The Company will encounter risks also connected with the separation of BP Norge from BP. BP currently performs certain functions for BP Norge, including, but not limited to, marketing and sale of oil and gas, IT services and accounts and payments services. The separation of such functions will not be completed at closing of the Transaction. As a result, BP Norge and the Company will depend on certain services and cooperation from BP for some time after closing of the Transaction to facilitate a smooth transition and complete separation. Under the SPA, BP and the Company have agreed that BP shall provide certain services to the Company/BP Norge in a transitional period. Any unforeseen delays or complications in the transition and separation process could increase integration costs and could adversely affect the Company's business, operating result and financial condition.

The Company may not be able to transfer the contracts currently held by BP Norge or transfer these on the same terms.

Some of BP Norge's contracts contain consent requirements triggered by the Transaction. The Company may not be able to obtain such consents, or may be unable to renew the existing contracts entered into by BP Norge or establish new contracts on terms as favourable as those contracts currently held. Further, the Company may incur transfer fees under certain contracts as a result of the Transaction. The Company's business, operating results, cash flow and financial condition may be adversely affected due to such transfer fees or in case of loss of contracts or if it fails to continue the current contracts or establish new contracts on similar terms or if substantial fees are incurred as a result of the Transaction.

The Company may be subject to potential loss of key BP Norge employees as a result of the Transaction.

Companies subject to acquisitions are generally subject to risk of employees leaving the acquired company and the Company risks losing experiencing with employees of BP Norge in connection with the Transaction. Although the Company currently does not have indications that this situation will arise, the loss of key employees in BP Norge could have an adverse effect on the Company's business, results of operation and financial position.

The Company may discover contingent or other liabilities within BP Norge

The Company will acquire the shares in BP Norge on «as is» terms, with certain limited warranties and indemnities from BP relating to inter alia ownership and title to the shares, tax, and certain other matters. The Transaction is otherwise based on a merger principle without subsequent adjustments between the parties. The Company may discover issues relating to BP Norge's business that may have a material adverse effect on the Company's business, results of operations, cash flow and financial condition, which the Company may not be entitled to seek remedy for from the Sellers.

1.2 Risks Relating to the Industry in which the Group and BP Norge Operates

The Company's business, results of operations, cash flow and financial condition depend significantly on the level of oil and gas prices and market expectations of these, and may be adversely affected by volatile oil and gas prices.

The Company's future revenues, cash flow, profitability and rate of growth depend substantially on prevailing international and local prices of oil and gas. Because oil and gas is globally traded, the Company is unable to control the prices it receives for the oil and gas it produces.

Both 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 willingness of the members of the Organisation of the 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 participants 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.

It is impossible to accurately predict future oil and gas price movements. The Company's profitability on a post tax basis is determined in large part by the difference between the income received from the oil and gas that the Company produces and its operational costs, taxation costs relating to extraction (including CO^2 fee, which are assessable irrespective of sales), as well as costs incurred in transporting and selling the oil and gas. Therefore, lower prices for oil and gas may reduce the amount of oil and gas that the Company is able to produce economically or may reduce the economic viability of the production levels of specific wells or of projects planned or in development to the extent that production costs exceed anticipated revenue from such production.

The economics of producing from some wells and assets may also result in a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production, causing a reduction in its oil and gas and development activities. In addition, certain development projects could become unprofitable as a result of a decline in price and could result in the Company 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.

In addition, a substantial material decline in prices from current price levels could reduce the Company's ability to refinance its outstanding credit facilities and may result in a reduced borrowing base under credit facilities available to the Company, including the RBL facility, and possibly require that a portion of the Company's financial debt be repaid. From time to time the Company may enter into agreements to receive fixed prices on its oil and gas production, or options or other trading arrangements, to offset the risk of revenue losses if commodity prices decline, however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay suppliers and others in the market based on such higher price.

The Company is affected by the general global economic and financial market situation.

The Company may be affected by the general state of the economy and business conditions, including but not limited to, the occurrence of recession and inflation, unstable or adverse credit markets, fluctuations in operating expenses, technical problems, work stoppages or other labour difficulties, property or casualty losses which are not adequately covered by insurance, and changes in governmental regulations, such as increased taxation or introduction of regulations increasing operating costs and capital expenditure which may materially and adversely affect the Company's business, operating results, cash flow and financial conditions.

The Company is dependent on finding, acquiring, developing and producing oil and gas reserves that are economically recoverable.

Oil and gas exploration and production activities are capital intensive and inherently uncertain in their outcome. Significant expenditure is required to establish the extent of oil and gas reserves through seismic and other surveys and drilling and there can be no certainty that further commercial quantities of oil and gas will be discovered or acquired by the Company. The Company's existing and future oil and gas appraisal and exploration projects may therefore involve unprofitable efforts, either from dry wells or from wells that are productive but do not produce sufficient net revenues to return a profit after development, operating and other costs. Even if the Company is able to discover or acquire commercial quantities of oil and gas in the future, there can be no assurance that these will be commercially developed.

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 of the Company to recover its costs and generate profits from its exploration and production activities could have a material adverse effect on the Company's business, results of operations, cash flow, financial condition and prospects.

Exploration and production operations involve numerous operational risks and hazards which may result in material losses or additional expenditures.

Developing oil and gas resources and reserves into commercial production involves a high degree of risk. The Company's exploration operations are subject to all the risks common in its industry. These hazards and risks include but are not limited to encountering unusual or unexpected rock formations or geological pressures, geological uncertainties, seismic shifts, blowouts, oil spills, uncontrollable flows of oil, natural gas or well fluids, explosions, fires, improper installation or operation of equipment and equipment damage or failure.

Given the nature of its offshore operations, the Company's exploration and drilling facilities are also subject to the hazards inherent in marine operations, such as capsizing, sinking, grounding and damage from severe storms or other severe weather conditions.

The offshore drilling conducted by the Company involves drilling risks including but not limited to high pressures and mechanical difficulties, which increase the risk of delays in drilling and of operational challenges arising, as well as material costs and liabilities occurring.

If any of these events were to occur in relation to any of the Company's Licenses, they could amongst other adverse effects result in environmental damage, injury to persons and loss of life and a failure to produce oil or gas in commercial quantities. They could also result in significant delays to drilling programmes, a partial or total shutdown of operations, significant damage to the Company's equipment and equipment owned by third parties and personal injury or death. These events can also put at risk some or all of the Company's licenses and could result in the Company incurring significant civil liability claims, significant fines or penalties as well as criminal sanctions potentially being enforced against the Company and/or its officers. The Company may also be required to curtail or cancel any operations on the occurrence of such events.

In its capacity as holder and operator of licenses under the Norwegian Petroleum Act, the Company is subject to strict statutory liability in respect of losses or damage suffered as a result of pollution caused by spills or discharges of petroleum from facilities covered by any of its licenses. This means that anyone who suffers damage or loss as a result of pollution caused by the Company in any of the license areas can claim compensation from the Company without needing to demonstrate that the damage is due to any fault on the Company's part.

Any of the above circumstances could materially and adversely affect the Company's business, prospects, financial condition, cash flow and results of operations.

The market in which the Company operates is highly competitive.

The oil and gas industry is very competitive. Competition is particularly intense in the acquisition of prospective and producing oil and gas licenses. The Company's competitive position depends on its geological, geophysical, engineering and management expertise, its financial resources, its ability to develop its assets and its ability to select, acquire, and develop proven reserves. The Company competes with a substantial number of other companies with larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development, and production of oil and gas reserves, but also carry on refining operations and market refined products. In addition, the Company competes with major oil and gas companies and other companies within industries supplying energy and fuel in the marketing and sale of oil and gas to transporters, distributors, and end users, including industrial, commercial, and individual consumers. The Company also competes with other oil and gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. In addition, equipment and other materials necessary to construct production and transmission facilities may be in short supply from time to time. Finally, companies not previously investing in oil and gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies will also provide competition for the Company.

As a result of this competitive environment, the Company may be unable to acquire licenses or on terms that it considers acceptable. As a result, the Company's revenues may decline over time, thereby materially and adversely affecting its business, results of operations, financial condition, cash flow and prospects.

The Company's business and financial condition could be adversely affected if the Norwegian tax regulations for the petroleum industry were amended.

The Company is subject to a special petroleum tax in Norway. Through its development projects the Company has built up a significant tax loss balance that can be utilised against future production revenues. There is no assurance that future political conditions in Norway will not result in the government adopting different policies for petroleum taxation. In the event there are changes to this tax regime, it could lead to investments being less attractive and prevent the Company's further growth.

Furthermore, the amounts of taxes the Company must pay could also change significantly as a result of new interpretations of the relevant tax laws and regulations or changes to such laws and regulations. In addition, taxing authorities could review and question the Company's tax returns leading to additional taxes and tax penalties which could be material.

The Company may be able to claim tax refund for its exploration costs, including all costs related to its drilling units. To the extent this assumption should be proven wrong or if such tax refund rights are limited or repealed, this may have a material adverse effect on the Company's financial position.

Pursuant to the Norwegian Assessment Act, the Norwegian tax authorities may change a tax payer's tax assessment within ten years after the tax year (changes in disfavour of the tax payer cannot be made more than two years after the tax year if the tax payer has provided the tax authorities with correct and complete information). Even though the Company is of the opinion that it has provided the tax authorities with correct and complete information, there can be no assurance that the tax authorities will not change, or at least claim to have the authority to change, the Company's tax assessment from previous tax years.

1.3 Risks Relating to the Business of the Group

The Company's business is concentrated in a few fields.

The Company's production of oil and gas is concentrated in a limited number of offshore fields. If mechanical or technical problems, storms or other events or problems affect the production on one of these offshore fields, it may have direct and significant impact on a substantial portion of the Company's production or if the actual reserves associated with any one of the Company's fields are less than the estimated reserves, the Company's results of operations and financial condition could be materially adversely affected. Further, some of the Company's material Licenses are in a development phase without production, including Johan Sverdrup and Ivar Aasen. The early stages, being the exploration or development period of a license are commonly associated with higher risk, requiring high levels of capital expenditure without a commensurate degree of certainty of a return on that investment.

There are risks related to determination and redetermination of unitised petroleum deposits.

According to the Norwegian Petroleum Act, unitisation is required if a petroleum deposit extends over several production licenses and these production licenses have a different ownership representation. Consensus must be achieved between the licensees on the most rational coordination of the joint development and ownership distribution of the petroleum deposit, which must be set out in an agreement regulating the joint production, transportation, utilisation and cessation of the petroleum activities related to the license. If such consensus is not reached within reasonable time, the Ministry of Petroleum and Energy (the "**MPE**") may determine how such joint petroleum activities shall be conducted, including the apportionment of the deposit.

Further, a unitisation agreement may include a redetermination clause, stating that the apportionment of the deposit between licenses can be adjusted within certain agreed time periods. Any such redetermination of the Company's interest in any of its licenses may have a negative effect on the Company's interest in the unitised deposit, including the Company's tract participating and paying interest. No assurance can be made that any such redetermination will be satisfactorily resolved, or will be resolved within reasonable time and without incurring significant costs. Any redetermination negatively affecting the Company's interest in a unit may have a material adverse effect on the Company's business, operating result, cash flow and financial condition.

The Company's development projects are associated with risks relating to delays and costs.

The Company's on-going development projects involve advanced engineering work, extensive procurement activities and complex construction work to be carried out under various contract packages at different locations onshore. Furthermore, the Company (together with its license partners), must carry out drilling operations, install, test and commission installations offshore and finally obtain governmental approval to take them into use, prior to commencement of production. The complexity of the Company's development projects makes them very sensitive to circumstances which may affect the planned progress or sequence of the various activities, as this may result in delays or costs increases. In particular, this applies to Company's development of Johan Sverdrup and Ivar Aasen. Johan Sverdrup, operated by Statoil, is a complicated multi-facility development while the Ivar Aasen development is the first development the Company has carried out as operator of a field.

Although the Company believes that the development projects will be completed on schedule in accordance with all license requirements and within the estimated budgets, the Company's current or future projected target dates for production may be delayed and significant cost overruns may incur due to delay, changes in any part of the Company's development projects, technical difficulties, project mismanagement, equipment failure, natural disasters, political, economic, taxation, legal, regulatory or social uncertainties, piracy, terrorism, visa issues or protests, which again may materially adversely affect the Company's future business, operating results, financial condition and cash flow. Ultimately, the Company risks that the rights granted under its licenses or agreement with the government may be forfeited and the Company may be liable to pay large sums, which could jeopardise its ability to continue operations.

Going forward, the Company, or the operator of licenses in which the Company has an interest, may be unable to explore, appraise or develop petroleum operations or the development or production of oil and/or gas is delayed as a result of, among other things, activities such as failure to obtain equipment, equipment failure, natural disasters, political, economic, taxation, legal, regulatory or social uncertainties, piracy, terrorism, visa issues or protests. Furthermore, the Company's estimated exploration costs are subject to a number of assumptions that may not materialise. Any such inability to explore appraise or develop petroleum operations or non-materialisation of assumptions regarding exploration costs, may have a material adverse effect on Company's growth ambitions, future business and revenue, operating results, financial condition and cash flow.

The Company's ability to control and manage such risks will depend on its influence and control in the various licenses.

The Company is exposed to risks relating to labour disputes.

Strikes, labour disruptions and other types of conflicts with employees of the Company or its contractors and license partners may adversely impact the Company's operations. Labour disruptions may be used not only for reasons specific to the Company's business, but also to advocate labour, political or social goals. Any such disruptions or delays in the Company's business activities may result in increased operational costs or decreased revenues from delayed or decreased (or zero) production and significant budget overruns. If such disruptions are material, they could materially adversely affect the Company's business, results of operations, cash flow and financial condition.

The Company is subject to third party risk in terms of operators and partners.

Where the Company is not the operator of a license, although it may have consultation rights or the right to withhold consent in relation to significant operational matters (depending on the level of the Company's interest and voting rights in such license), it has limited control over management of its assets and mismanagement by the operator or disagreements with the operator as to the most appropriate course of action may result in significant delays, losses or increased costs to the Company.

The terms of the relevant operating agreements generally impose standards and requirements in relation to the operator's activities. However, there can be no assurance that such operators will observe such standards or requirements and this could result in a breach of the relevant operating agreement.

There is a risk that other partners with interests in the Company's Licenses may not be able to fund or may elect not to participate in, or consent to, certain activities relating to those Licenses which require that party's consent, including but not limited to, decisions relating to drilling programs, such as the number, identity and sequencing of wells, appraisal and development decisions, decisions relating to production and also any decision to not drill at all (e.g. "drill or drop" decisions). In these circumstances, it may not be possible for such activities to be undertaken by the Company alone or in conjunction with other participants at the desired time or sequence or at all. Inversely, decisions by the other partners to engage in certain activities as aforesaid, may also in the circumstances be contrary to the Company's voting not to engage in or commence such activities and may imply that the Company will be bound to incur its share of costs in relation thereto, which may become significant.

The license partners in the Company's Licenses have joint and several liability for obligations arising out of the license. Such liability is unlimited. Other license partners may default on their obligations to fund capital or to cover obligations and liabilities towards third parties. In such circumstances, the Company may be required under the terms of the relevant operating agreement or otherwise to contribute all or part of such funding shortfall itself.

Any disagreement, absence of consent, delay, opposition, breach of agreement, or inability to undertake activities or failure to provide funding of the kind identified above could materially adversely affect the Company's business, prospects, financial condition, cash flow and results of operation.

The Company is exposed to losses on its operated assets.

The Company is operator for several of its licenses. Although the operatorship is performed based on a "no gain, no loss" principle, the partners in the respective licenses are provided with audit rights and other rights that may ultimately inflict losses on the Company as an operator should the Company be found not to have managed the operatorship in compliance with relevant requirements. In the event the Company incurs such losses, this could have a material adverse effect on the Company's financial position, cash flow and results of operation.

The Company is subject to third-party risk in terms of contractors.

Market conditions may impair the liquidity situation of contractors and consequently their ability to meet their obligations towards the Company. This could materially adversely affect the Company's business, operating results, cash flow and financial condition.

The Company's future growth and performance depend on a number of factors, which outcome cannot be guaranteed.

The Company's future growth and performance will partly depend on its ability to manage growth effectively, including, but not limited to its ability to integrate the business of BP Norge, adequately manage the number of employees, technical solutions including IT systems and software, operational efficiency in the "new" Company's organisations in Oslo, Stavanger, Trondheim, Sandnessjøen and Harstad respectively. The Company's failure to successfully grow its operations, and/or to handle such growth, could materially adversely affect its business, operating results, cash flow and financial condition.

The Company may not have access to necessary infrastructure for the transportation of oil and gas.

The Company is dependent on capacity to transport and sell oil and gas. The Company, or the license group in which the Company holds an interest, may need to rely on access to third party infrastructure to be able to transport produced oil and gas, e.g. by depending on obtaining approval for construction of pipelines in close proximity of or crossing third party's infrastructure or being able to acquire the necessary capacity to transport gas. There can be no assurance that the Company will be able to get access to necessary infrastructure at an economically justifiable cost or access necessary infrastructure at all. If such access is unavailable or unavailable at an economically justifiable cost, the Company's income relating to the sale of oil and gas may be reduced which again may materially adversely affect the Company's business, operating results, cash flow and financial condition.

The Company faces risks related to decommissioning activities and related costs.

There are significant uncertainties relating to the estimated costs for decommissioning of the Company's current licenses including the schedule for removal of each installation. No assurance can be given that the anticipated costs and time of removal are correct and any deviation from such estimates may have a material adverse effect on the Company's business, operating results, cash flow and financial condition. Also, the Company is jointly and severally liable for decommissioning costs together with the other licensees of each license. Hence, if one or more of the other licensees fail to cover their share of the decommissioning costs, the Company can be held liable for such licensee's share of decommissioning costs. Furthermore, under the Norwegian Petroleum Act, a licensee assigning its interest in a license remains secondarily liable for decommissioning costs related to facilities existing at the time of assignment in the event that the decommissioning costs are not covered by the current licensees. Any significant increase in decommissioning costs relating to the Company's current or previous licenses may materially and adversely affect the Company's business, financial condition, cash flow and results of operation.

The Company is exposed to political, regulatory and unrest risks.

The Company is conducting exploration and development activities in Norway and is dependent on receipt of government approvals and permits to develop its assets. The Company is qualified to conduct its operations on the Norwegian Continental Shelf (the "**NCS**"), however, there is no assurance that future political conditions in Norway will not result in the government adopting new or different policies and regulations on exploration, development, operation and ownership of oil and gas, environmental protection, and labour relations. The Company may be unable to obtain or renew required drilling rights, licenses, permits and other authorisations and these may also be suspended, terminated or revoked prior to their expiration. This may affect the Company's ability to undertake exploration and development activities in respect of present and future assets, as well as its ability to raise funds for such activities. Also, there can be no assurance that the Company's Licenses granted by the MPE will be extended or not be revoked in the future and there is also a risk that the MPE stipulates conditions for any such extension or for not revoking any licenses. Lack of governmental approvals or permits or delays in receiving such approval may delay the Company's operations, increase its costs and liabilities or affect the status of the Company's contractual arrangements or its ability to meet its contractual obligations. Any of the above factors may have a material adverse effect on the Company's business, results of operation, cash flow and financial conditions.

The Company is vulnerable to adverse market perception.

The Company is vulnerable to adverse market perception as it must display a high level of integrity and maintain the trust and confidence of investors, license partners, public authorities and counterparties. Any mismanagement, fraud or failure to satisfy fiduciary or regulatory responsibilities, allegations of such activities, or negative publicity resulting from such other activities, or the association of any of the above with the Company could materially adversely affect the Company's reputation and the value of its brand, as well as its business, operating results, cash flow and financial position.

The Company may be subject to liability under environmental laws and regulations.

All phases of the oil and gas 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, among other things, restrictions and prohibitions on spills, and releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites are operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. Many participants in the oil and gas industry are subject to legislation in relation to the emission of carbon dioxide, methane, nitrous oxide and other so-called greenhouse gases. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, in addition to loss of reputation. Environmental legislation 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, gas or other pollutants into the air, soil or water may give rise to material liabilities to foreign governments and third parties and may require the Company to incur material costs to remedy such discharge. No assurance can be given that environmental laws will not result in a curtailment or shut down of production or a material increase in the costs of production, development or exploration activities or otherwise materially adversely affect the Company's financial condition, results of operations, cash flow, financial condition or prospects.

Furthermore, environmental concerns relating to the oil and gas industry's operating practices are expected to increasingly influence government regulation and consumption patterns which favour cleaner burning fuels such as gas. Future compliance with existing emissions legislation or any future emissions legislation could adversely affect the Company's profitability. Future legislative initiatives designed to reduce the consumption of hydrocarbons could also have an impact on the ability of the Company to market its oil and gas and/or the prices which the Company is able to obtain, which in turn may adversely affect the Company's financial condition, results of operations, cash flow, financial condition or prospects.

The Company has been operating in the oil and gas business for several years. Even though the Company are not aware of any liabilities related to current or historical operations relating to its business, the Company may potentially be subject to various liabilities such as pollution and environmental liabilities related to its business or the business of BP Norge.

The Company's insurance may not provide sufficient funds to protect the Company from liabilities that could result from its operations.

Oil and gas exploration, development, and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and gas wells, production facilities, other property, and the environment or in personal injuries, in addition to business interruption. The Company maintains a number of separate insurance policies to protect its core businesses against loss and/or liability to third parties. Risks insured against generally include general liability, workers' compensation and employee liability, professional indemnity, loss of production and material damage. However, in accordance with industry practice and as a result of the Company's assessment of its needed insurance programme profile from time to time, the Company is not fully insured against all of these risks. Furthermore, not all mentioned risks are insurable, or only insurable at a disproportionately high cost. Although the Company maintains liability insurance in an amount that it considers adequate and consistent with industry standard, the nature of these risks is such that liabilities could materially exceed policy limits or not be insured at all, in which event the Company could incur significant costs that could have adverse effect on its financial condition, results of operation and cash flow. Any uninsured loss or liabilities, or any loss and liabilities exceeding the insured limits, may adversely affect the Company's business.

Availability of drilling equipment and other required equipment and access restrictions may affect the Company's operations.

Oil and gas exploration and development activities are dependent on the availability of specialised equipment, including, but not limited to drilling and related equipment in the particular areas where such activities will be conducted. From time to time the demand for such limited equipment may be high or access restrictions will affect the availability and cost of such equipment to the Company and from time to time delays exploration and development activities. Also, to the extent the Company is not the operator of its oil and gas assets, the Company will be dependent on such operators for the timing of activities related to such assets and will be largely unable to direct or control the activities of the operators. If any of these risks materialize, they may have a material adverse effect on the Company's business, results of operations, cash flow or financial condition.

The Company's oil and gas production could vary significantly from reported reserves and resources.

The Company's reserve evaluations have been prepared in accordance with existing guidelines. Certification of the reserves and resources of the Company are carried out on an annual basis by an independent third party. These evaluations include a number of assumptions relating to factors such as initial production rates, recovery rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and gas, operating costs, and royalties and other government levies that may be imposed over the producing life of the reserves and resources. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. Hence, although the Company has an understanding of the life expectancy of each of its assets, the life of an asset may be shorter than anticipated. Among other things, evaluations are based, in part, on the assumed success of exploration activities intended to be undertaken in future years. The reserves, resources and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploration activities do not achieve the level of success assumed in the evaluations, and such reductions may have a material adverse effect on the Company's business, results of operations, cash flow and financial condition. Accordingly, investors should be cautious in reviewing reserve and resources figures included in this Information Memorandum.

Accounting policies may result in non-cash charges and write downs considered unfavourably by the market.

IFRS requires that management apply certain accounting policies and make certain estimates and assumptions, which affect reported amounts in the consolidated financial statements of the Company. The accounting policies may result in non-cash charges to net income and material write downs of net assets in the financial statements. Such non-cash charges and write downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a significant decline in the trading price of the Company's shares.

The Company may not be successful in attracting and retaining sufficient skilled employees.

The successful development and performance of the Company's business depends on its ability to attract and retain skilled professionals with appropriate experience and expertise. Attracting and retaining additional key personnel will assist in the expansion of the Company's business and the loss of key employees could also have a material negative effect on the Company. The Company faces significant competition for skilled personnel and there can be no assurance that the Company will have access to sufficient skilled and experienced professionals.

There is no assurance that the Company will successfully attract and retain personnel required to continue to expand its business and to successfully execute its business strategy and failure to attract or retain employees could result in the inability to maintain the appropriate technological standard or take advantage of new opportunities that may arise, which may in turn lead to a subsequent decline in competitiveness and could materially adversely affect the Company's business, operating results, cash flow and financial condition.

The Company faces the risk of litigation or other proceedings in relation to its business.

The Company faces the risk of litigation and other proceedings in relation to its business. The outcome of any litigation may expose the Company to unexpected costs and losses, reputational and other non-financial consequences and diverting management attention, which may in turn materially adversely affect the Company's business, operating results, cash flow and financial condition.

The Company may experience conflicts of interest.

There are potential conflicts of interest to which the directors, officers and principal shareholders of the Company will be subject to in connection with the operations of the Company. Some of the directors, officers and principal shareholders may become engaged in other oil and gas interests on their own behalf and on behalf of other companies resulting in a conflict of interest and situations may arise where the directors and officers will be in direct competition with the Company. Such conflicts, if any, will be subject to the procedures and remedies under Norwegian company law, but may not prevent adverse effects for the Company with regard to such conflicts. The directors, officers and principal shareholders of the Company may not devote their time on a full-time basis to the affairs of the Company as a result of such conflicts. Certain Directors of the Board of the Company own collectively, directly and indirectly, a significant part of the outstanding share capital of the Company, and will therefore have the possibility to influence the decision-making in the Company.

The Company's development projects require substantial capital expenditures.

The Company makes and expects to continue to make substantial capital expenditures in its business for the development, production and acquisition of oil and natural gas reserves. The intention is to finance future capital expenditures with cash flow from operations and borrowings under the Company's debt facilities. The cash flows from operations and access to capital are subject to a number of variables which the Company does not control, including:

- proved reserves;
- the level of oil and natural gas to be produce from existing wells;
- sales price of oil and gas; and
- the ability to acquire, locate and produce new reserves.

If revenues or the borrowing base under the Company's RBL facility (see Section 3.8 "Presentation of Det norske oljeselskap—Capital Resources— The Company's Borrowing Arrangements—Revolving Borrowing Base Facility") decrease as a result of lower oil or gas prices, operating difficulties, declines in reserves or for any other reason, the Company may have limited ability to obtain the capital necessary to sustain operations at current levels. The Company's current debt facilities place certain restrictions on the ability to obtain new financing. If additional capital is needed, the Company may not be able to obtain debt or equity financing. If cash generated by operations or cash available under the RBL facility and RCF facility (see Section 3.8 "Presentation of Det norske oljeselskap—Capital Resources— The Company's Borrowing Arrangements— Revolving Credit Facility" are not sufficient to meet the Company's capital requirements, the failure to obtain additional financing could result in a curtailment of operations relating to development of prospects, which in turn could lead to a decline in the Company's oil and natural gas reserves, or if it is not possible to cancel or stop a project, an legal obligation to carry out the project contrary to the Company's desire or with negative economic impact. All of the above could adversely affect The Company's production, revenues and results of operations as well as having an adverse effect on the Company's ability to service its indebtedness

1.4 Risks Relating to the Shares

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 control of the Company, including quarterly variations in operating results, adverse business developments, changes in financial estimates and investment recommendations or ratings by securities analysts, announcements by competitors of new product and service offerings, significant contracts, acquisitions or strategic relationships, publicity about their products and services or their competitors, lawsuits, unforeseen liabilities, changes to the regulatory environment or general market conditions.

The Company's ability to distribute dividends is subject to financial capacity and absence of restrictions under loan agreements and other restrictions.

The market value of the Shares may fluctuate significantly and may not reflect the underlying asset value of the Company.

The market value of the Shares can fluctuate significantly and may not always reflect the underlying asset value of the Company. A number of factors outside the control of the Company may have an impact on its performance and the price of the Shares. Such factors include but are not limited to a change in market sentiment regarding the Shares and the Company, the operating and share price performance of other companies in the industry and markets in which the Company operates, speculation about the Company's business in the press, media or investment community, changes to the Company's profit estimates, the publication of research reports by analysts and general market conditions. If any of these factors actually occurs, this may have a material adverse effect on the pricing of the Shares.

The market price of the Shares could decline as a result of sales of a large number of Shares in the market or the perception that these sales could occur. Aker Capital AS is the company's main shareholder, and has not lock up commitment on its shareholding After completion of the proposed transaction there is no lock-up agreement between Aker Capital AS, the Sellers and the Company.

Future issuances of shares or other securities may dilute the holdings of shareholders and could materially affect the share price.

It is possible that the Company may in the future decide to offer shares or other securities in order to finance new capital-intensive projects, in connection with unanticipated liabilities or expenses or for any other purposes. Any such offering could 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, and any offering could have a material adverse effect on the market price of the shares.

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

Beneficial owners of 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 (a) re-registered in their names with the VPS, prior to the Company's general meetings or (b) the registered nominee holder grants a proxy to such beneficial owner in the manner provided in the Articles of Association in force at that time and pursuant to the contractual relationship, if any, between the nominee and the beneficial owner, to vote for such Shares. The Company cannot guarantee that beneficial owners of the Shares will receive the notice of a general meeting of shareholders of the Company 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. Any persons that hold their Shares through a nominee arrangement should consult the nominee to ensure that any Shares beneficially held are voted for in the manner desired by such beneficial owner.

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

The Shares have not been registered under the U.S. Securities Act or any U.S. state securities laws or any other jurisdiction outside of Norway and are not expected to be registered in the future. As such, the Shares may not be offered or sold except pursuant to an exemption from the registration requirements of the U.S. Securities Act and applicable securities laws. 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.

Shareholders outside of Norway are subject to exchange rate risk.

The Company's Shares are priced in NOK, and any future payments of dividends on the Shares may be denominated in NOK. Accordingly, any investor outside Norway may be subject to adverse movements in the NOK against their local currency, as the foreign currency equivalent of any dividends paid on the shares or price received in connection with any sale of the shares could be materially adversely affected.

2. RESPONSIBILITY STATEMENT

The Board of Directors of Det norske oljeselskap ASA accepts responsibility for the information contained in this Information Memorandum. The members of the Board of Directors confirm that, 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 omissions likely to affect its importance.

Oslo, 9 September 2016

The Board of Directors of Det norske oljeselskap ASA

Øyvind Eriksen (Chairman)
Anne Marie Cannon (Deputy Chair)
Kjell Inge Røkke
Kitty Hall (Katherine J. Martin)
Gro Kielland
Kjell Pedersen
Trond Brandsrud
Terje Solheim
Lone Olstad
Bjørn Thore Ribesen

3. PRESENTATION OF DET NORSKE OLJESELSKAP

3.1 Introduction

The Company is an oil and gas company with exploration and production activities on the NCS and is listed on the Oslo Stock Exchange under the ticker "DETNOR". The Company is a public limited liability company registered under Norwegian law and domiciled in Norway. As of the date of this Information Memorandum and prior to completion of the Transaction, the Company is primarily an offshore exploration and development company with a total of 89 licenses (43 as operator). Please see Section 3.5 "License Portfolio, Reserves and Resources" for further details.

The Company ranks among the largest independent Norwegian oil producers and is one of the largest listed independent exploration and production ("**E&P**") companies in Europe.

The company had 535 employees as of 30 June 2016. The company has steadily developed a competent and experienced organisation that has been scaled up over the last years, mainly due to the Ivar Aasen development project where the Company is operator and to the acquisition of Marathon Oil Norway AS that included operatorship of the Alvheim area fields. During the last 12 months the Company has also acquired Svenska Petroleum Exploration AS, Premier Oil Norge AS and the Norwegian petroleum licenses of Noreco ASA. The Company has also acquired additional license interests from Centrica Resourcnces Norge AS in the Frigg Gamma Delta discovery (including operatorship) and the Rind discovery.

Senior Management comprises individuals with experience from the oil and gas industry. Previous management employment includes well-known companies like Statoil, Aker, Saga, Hydro, Marathon and ConocoPhillips.

The organisation is based in four office locations, namely Trondheim, Oslo, Stavanger and Harstad. The Company's registered headquarters is in Trondheim (Føniks, Munkegata 26, 7011 Trondheim). The head office functions are divided between Oslo and Trondheim.

The Company has taken part in significant discoveries in recent years, of which the Ivar Aasen and the Johan Sverdrup fields will influence the Company's production profile over the next several years. Additionally the Company participates in the Gina Krog development and operates the Viper-Kobra development in the Alvheim area. The Ivar Aasen field has planned production start-up in Q4 2016. The Johan Sverdrup field has an anticipated commencement of production in Q4 2019. The Johan Sverdrup field is among the largest oil discoveries on the NCS, with the operator Statoil Petroleum AS, estimating the total field resources to be in the range of 1,900 to 3,000 million barrels of oil equivalent ("**boe**").

As of 31 December 2015, the Company has a participating interest in 17 fields containing reserves, of which 9 are in production and 8 are under development. The Company's total net proven reserves (P90/1P) as of 31 December 2015 is estimated at 374 million boe. The total net proven plus probable reserves (P50/2P) are estimated at 498 million boe. The Company has reported a total production of 21.9 million boe in 2015 which is equivalent to an average daily production of 60,000 barrels of oil equivalent per day ("**boepd**").

3.2 Strengths and Strategies

Vision and Strategy

The Company has evolved from being an exploration company to becoming a full-fledged oil company with activities within exploration, development and production. From the establishment of Pertra, through the merger with NOIL (the Norwegian business of DNO ASA) and Aker Exploration and with the acquisitions of Marathon Norway, Svenska Petroleum Exploration and Premier Oil Norge, the Company has grown its' resource base and organisation. The development of the Ivar Aasen and the Johan Sverdrup fields will further grow the Company.

Exploration has traditionally been the Company's core activity since its inception; over the last 10 years, it has been one of the largest oil and gas companies with respect to operated exploration drilling activity on the NCS. In addition to organic growth, the Company also continuously assesses potential acquisitions on the NCS offering access to assets and potential upside that is in line with the Company's strategy. If deemed beneficial to achieve the Company's overall strategy and objectives, the Company may also from time to time reduce its ownerships interest in certain licenses or enter into farm-down arrangements. In May 2016, the Company was awarded three licenses in the 23rd licensing round. The awards included one operatorship and two partnerships, all in the Barents Sea.

The Company reached a milestone when the Jette started production in May 2013, which was the first oil produced by the Company as operator. With the acquisition of Marathon Oil Norway, the Company became operator of Alvheim, Vilje, Volund and Bøyla, which all are tied back to the Alvheim FPSO. Ivar Aasen, with first oil scheduled for Q4 2016, will be the next building block in the Company's history and development in to a significant operator of producing fields.

The Company's vision is;

”Always moving forward to create value on the Norwegian continental shelf”

This will be achieved through organic growth of exploration, development and production activities and further acquisitions.

Values

The Company has four main values:

- To be **responsible** by putting safety first and to strive to create the highest possible value for Shareholders and for society;
- To be **enquiring** by being curious and aiming for new and better solutions;
- To be **reliable** by building trust and a good reputation through reliability and consistent behaviour; and
- To be **committed** by always being committed to each other, the Company and society.

Strengths

Strong asset base

The Company has a robust resource base, classified in accordance with the Society of Petroleum Engineer’s (“**SPE**”) “Petroleum Resources Management System” (“**PRMS**”). This classification system is consistent with Oslo Stock Exchange’s requirements for the disclosure of hydrocarbon reserves and contingent resources. Total net proven reserves (P90/1P) as of 31.12.2015 to the Company are estimated at 374 million boe. Total net proven plus probable reserves (P50/2P) are estimated at 498 million boe. The Company has included recoverable volumes from a full field development scenario as undeveloped reserves for Johan Sverdrup. Only Phase 1 has an approved Plan for Development and Operations (“**PDO**”). Total net production to the Company averaged 60 000 boepd in 2015.

Strong Norwegian foothold and relationships

The Company has strong relationships to and experience with the Norwegian oil industry, including authorities, oil service suppliers, government and other key stakeholders. The majority of the Company’s employees come from other key Norwegian players such as Statoil, Hydro and Saga, Marathon Oil Norway. Knowledge of the Norwegian regulations, tax systems and NORSOK standard provides the Company with good basis for safe operations and conducting business.

Ownership structure

The Company is a Norwegian public limited liability company (ASA) listed on the Oslo Stock Exchange and established under Norwegian law. As at 25 July 2016, the largest shareholders in the Company are Aker Capital AS, with 49.99% ownership share, and Folketrygdefondet, with 7.89% of the ownership share. Aker Capital AS is a 100% subsidiary of Aker ASA. Through Aker ASA's indirect ownership in the Company, the Company is backed by a long-term industrial owner with a strong balance sheet. Subsequent to the Transaction, Aker Capital AS will hold an interest of approximately 40.00% and the BP Group will hold an interest of approximately 30.00% and minority shareholders will hold the remaining 30.00% of the interests, cf. section 4.5 “The Transaction - Consideration”.

3.3 History and Development

2001 .... Pertra AS was founded by Petroleum Geo-Services (PGS) ASA as an E&P company with focus to exploit the potential of petroleum resources on the NCS. The potential benefits of collaboration between Pertra and PGS were the main argument for establishment. Pertra was approved as a license holder and operator on the Norwegian continental shelf in February 2002, being the first Norwegian newcomer on the NCS over the last ten years.

2002 .... Pertra acquired license shares in PL 038 which contains the Company’s producing Varg field. Petra was the operator of Varg until 2005 with very good results. Pertra’s work with Varg has often been described as a success story within the Norwegian oil history.

2005 .... PGS sold Pertra to Talisman Energy. Soon after, the management team in Pertra established a new company, Pertra Management. The new company negotiated a contract with Talisman Energy for the purchase of some of the assets Talisman had acquired from Pertra’s former owner. The result was the basis for the establishment of a new E&P company in Trondheim. “New” Pertra was now established, with financial support from local investors.

2006 .... The “new” Pertra was listed on the Oslo Stock Exchange as Pertra ASA, with the founders’ ambition to gradually build a fully-fledged Norwegian E&P company on the NCS.

2007-2008...... Pertra merged with the Norwegian arm of DNO, which was organised through the company NOIL Energy. DNO changed its name to DNO International, while Pertra, as the surviving entity of the merger, changed its name to Det norske oljeselskap ASA or simply “Det norske” colloquially. The two companies were formally merged in 2008. In the same year, the Company discovered Draupne, later renamed to Ivar Aasen. The Company is the operator and holds an ownership interest of 34.7862% in the unit comprising the Ivar Aasen and West Cable deposits.

2009 .... A merger with Aker Exploration, an E&P company established by the Aker group in 2006, was formally approved in October 2009 with Aker Exploration as the surviving entity. The name of the merged company remained Det norske oljeselskap ASA. Aker ASA became the Company’s largest Shareholder with an ownership interest of around 40%. Aker ASA has later increased its ownership stake in the Company and currently holds 49.99% of the shares in the Company.

2010 .... High level of exploration activities. The Company participates in 15 wells, of which nine as operator. The Company conducts its first production test on the Ivar Aasen field – with very positive results.

2011 .... The Company participated in the significant discovery made by Statoil, at that time called Aldous Major, later to be known as part of Johan Sverdrup. The Company has 20% ownership interest in PL 265.

2012 .... The Company submits the PDO for the Ivar Aasen field to the Ministry of Petroleum and Energy. This is the Company’s first major development as operator.

2013 .... With start-up of production on Jette, the Company becomes a fully-fledged oil company with activities in the entire chain of value creation; exploration, development and production.

2014 .... The Company entered into an agreement to acquire all outstanding shares in Marathon Norway. Following completion, the Company has diversified its asset base to support further growth.

2015 .... On 13 February 2015 the PDO for Johan Sverdrup was submitted to the MPE. The Company acquired Svenska Petroleum Exploration AS and Premier Oil Norge AS. These acquisitions strengthened the Company’s position in the Krafla/Askja, Garantiana, Frigg and Frøy areas.

2016 .... On 18 April 2016 the Company entered into an agreement to acquire Centrica Resources Norge AS’s participating interests in the Frigg Gamma Delta and Rind discoveries. The Ivar Aasen platform deck sailed away from the yard and was successfully installed on the Ivar Aasen field. The Company also acquired the Norwegian petroleum licenses of Noreco Norge AS, including its participating interests in the Gotha discovery.

3.4 The Business of the Group

The Company is an E&P company with its business being the exploration, development and production of petroleum on the NCS. As outlined in more detail in section 3.5 “License Portfolio, Reserves and Resources” below as of 30 June 2016 the Company had a license portfolio of 89 licenses of which the Company operates 43 licenses.

The Company’s main income comes from the sale of petroleum products from producing fields on the NCS. The Company operates the producing fields Alvheim, Volund, Vilje, Bøyla and Jette. In 2015 the Company had an oil production volume of 19.307.898 boe and a gas production volume of 2.593.733 boe. In 2015 the Company’s total petroleum revenue was USD 1.158.683.000, of which USD 1.044.548.000 was oil income and USD 110.909.000 gas income with an additional USD 3.227.000 of tariff income. For the first 6 months of 2016 the corresponding revenue was USD 472.040.000.

The Company is also the operator of the development of the Ivar Aasen field. Ivar Aasen is a large and important project for the Company, and the work is progressing well. In July 2016 the Ivar Aasen topside was installed successfully according to plan and without incident on the Ivar Aasen field.

The Company is partner in the Johan Sverdrup field, where Statoil Petroleum AS is the operator. The development solution was decided in February 2014 and the PDO for phase 1 of the field was delivered in February 2015. First oil from the Johan Sverdrup field is anticipated in late 2019 and the field is expected to produce for 50 years.

In July 2015, the MPE determined the allocation of participating interests in the unitization of the Johan Sverdrup field. Following a complaint by the Company the decision was upheld by the King in counsel on 18 December 2015. The

Company does not agree with this allocation, but it has currently not decided whether further measures will be taken to challenge the allocation of the participating interests in the unit.

The Company's producing assets are Alvheim (65.0% (excluding Boa), operator), Volund (65.0%, operator), Bøyla (65.0%, operator) and Vilje (46.9%, operator). In addition, the Company participates in the Jette unitized field (70%, operator), the Atla field (10.0%, license partner), the Varg field (5.0%, license partner) and Jotun unitized field (7.0%, license partner).

3.5 License Portfolio, Reserves and Resources

License Portfolio

As of 30 June 2016 the Company had a license portfolio of 91 licenses, 44 as operator and 47 as license partner as set out in the table below.

The Company is dependent on these licenses as they forms the basis for all of the Company's activities and income.

Prodcution Licenses (License Partner)

Field	Company Participating Interest	Operator	Expiry
PL 006 C	15.0%	Faroe Petroleum Norge AS	31.12.2028
PL 018 DS	13.3%	Maersk Oil Norway AS	31.12.2028
PL 019 C	30.0%	Repsol Norge AS	01.09.2018
PL 026	30.0%	Total E&P Norge AS	23.05.2025
PL 029 B	20.0%	Statoil Petroleum AS	31.12.2032
PL 035	50.0%	Statoil Petroleum AS	14.11.2022
PL 035 C	50.0%	Statoil Petroleum AS	14.11.2022
PL 038	5.0%	Repsol Norge AS	01.04.2021
PL 038 D	30.0%	Repsol Norge AS	01.04.2021
PL 048 D	10.0%	Statoil Petroleum AS	18.02.2018
PL 102 C	10.0%	Total E&P Norge AS	01.03.2025
PL 102 D	10.0%	Total E&P Norge AS	01.03.2025
PL 102 F	10.0%	Total E&P Norge AS	01.03.2025
PL 102 G	10.0%	Total E&P Norge AS	01.03.2025
PL 265	20.0%	Statoil Petroleum AS	27.01.2037
PL 272	50.0%	Statoil Petroleum AS	14.11.2022
PL 457	40.0%	Wintershall Norge AS	28.02.2018
PL 457 BS	40.0%	Wintershall Norge AS	31.12.2036
PL 492	60.0%	Lundin Norway AS	28.02.2018
PL 502	22.2%	Statoil Petroleum AS	23.01.2018
PL 507	25.0%	Statoil Petroleum AS	23.01.2019
PL 533	35.0%	Lundin Norway AS	15.11.2017
PL 550	10.0%	Tullow Oil Norge AS	19.06.2018
PL 554	30.0%	Total E&P Norge AS	19.02.2018
PL 554B	30.0%	Total E&P Norge AS	19.02.2018
PL 554C	30.0%	Total E&P Norge AS	19.02.2018
PL 613	20.0%	DONG E&P Norge AS	13.05.2019
PL 616	20.0%	Edison Norge AS	03.08.2019
PL 617	35.0%	MOL Norge AS	03.11.2020
PL 627	20.0%	Total E&P Norge AS	03.02.2021
PL 627 B	20.0%	Total E&P Norge ASA\	03.02.2021
PL 653	30.0%	DEA Norge AS	08.02.2021
PL 672	25.0%	Repsol Norge AS	08.02.2018
PL 689	20.0%	DONG E&P Norge AS	08.02.2022
PL 689 B	20.0%	DONG E&P Norge AS	08.02.2022

PL 694	20.0%	DEA Norge AS	08.02.2021
PL 722	20.0%	ENGIE E&P Norge AS	21.06.2019
PL 778	20.0%	Lundin Norway AS	06.02.2022
PL 782 S	20.0%	ConocoPhillips Skandinavia AS	06.02.2023
PL 782 SB	20.0%	ConocoPhillips Skandinavia AS	06.02.2023
PL 797	25.0%	Lotos Exploration and Production Norge AS	06.02.2022
PL 804	30.0%	Wintershall Norge AS	06.02.2022
PL 813	3.3%	Statoil Petroleum AS	05.02.2020
PL 842	30.0%	Capricorn Norge AS	05.02.2023
PL 844	20.0%	DONG E&P Norge AS	05.02.2025
PL 852	40.0%	Centrica Resources (Norge) AS	10.06.2021
PL 857	20.0%	Statoil Petroleum AS	10.06.2020
Total	**47**		

Production Licenses (Operator)

Field	Company Participating Interest	Expiry
PL 001B	35%	31.12.2036
PL 026B	90%	23.05.2025
PL 027D	100%	01.03.2021
PL 028B	35%	31.12.2036
PL 036C	65%	11.06.2021
PL 036D	46.9%	11.06.2021
PL 088BS	65%	09.03.2022
PL 103B	70%	01.03.2021
PL 150	65%	08.07.2024
PL 150B	65%	04.08.2016
PL 169C	50%	01.03.2030
PL 203	65%	02.02.2032
PL 203B	65%	08.02.2019
PL 242	35%	31.12.2036
PL 340	65%	17.12.2029
PL 340BS	65%	17.12.2029
PL 364	100%	06.01.2019
PL 406	50%	16.02.2017
PL 407	50%	16.02.2017
PL 442	90%	15.06.2017
PL 460	100%	01.03.2018
PL 504	47.6%	01.03.2021
PL 539	40.0%	19.08.2018
PL 626	50%	03.08.2019
PL 659	20%	03.02.2020
PL 677	60%	08.02.2020
PL 690	50%	08.02.2021
PL 701	40%	08.02.2020
PL 709	40%	21.06.2016
PL 715	40%	21.06.2019
PL 724	40%	07.02.2021
PL 724B	65%	07.02.2021
PL 736S	60%	07.02.2022

PL 748	20%	07.02.2022
PL 762	40%	07.02.2022
PL 777	40%	06.02.2022
PL 777B	40%	06.02.2022
PL 790	30%	06.02.2022
PL 814	40%	05.02.2023
PL 818	40%	05.02.2023
PL 821	60%	05.02.2023
PL 822S	60%	05.02.2023
PL 843	40%	05.02.2025
PL 858	40%	10.06.2020
Total	**44**	

An application for extension of PL 150B has been sent, but no response has currently been received from the MPE. PL 460 is decided to be relinquished to the Norwegian state, but this has not been formally approved by the MPE. PL 709 has been relinquished, but confirmation from the MPE has not been received.

Reserves, Resources and Operating Data

The Company retains AGR Petroleum Services AS for the purposes of certifying the reserves and contingent resources associated with its asset portfolio and internal reserve estimates. The Company's reserves are estimated and classified in accordance with the SPE's PRMS, which is consistent with the Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources

Discoveries

In 2015 and so far in 2016, the Company made discoveries both in the Barents Sea and in the North Sea and the Company has announced that these discoveries increased its resources above the target for the year. The majority of the increase in resources was due to the Gohta (PL492) and the Askja (PL272) discoveries. Both discoveries are assumed to have commercial potential, but no field development planning has yet taken place.

With the discoveries in the Company's current asset portfolio, it is expected that commercial activity will have duration past the year 2050.

Exploration Activity

In 2015 the Company has participated in nine (9) exploration and appraisal wells and have proved hydrocarbons in five (5) wells. Below is an overview of the Company's exploration activity in 2015 and so far in 2016:

License	Prospect/Field	Company Interest	Drilling operator	Type of well	Area	Result
2015						
PL 035	Krafla N	50 %	Statoil Petroleum AS	Appraisal	North Sea	Oil
PL 001 B	Ivar Aasen	34.8 %	Det norske	Appraisal	North Sea	Oil
PL 001 B	Ivar Aasen	34.8 %	Det norske	Appraisal	North Sea	Oil
PL 627	Skirne East	20 %	Total E&P Norge	Wildcat	North Sea	Gas /Condensate
PL 029 B	Gina Krog	3.3 %	Statoil Petroleum AS	Appraisal	North Sea	Oil / Gas
PL 001 B	Ivar Aasen	34.8 %	Det norske	Appraisal	North Sea	Oil
PL 029 B	Gina Krog	3.3 %	Statoil Petroleum AS	Appraisal	North Sea	Dry
PL 001 B	Ivar Aasen	34.8 %	Det norske	Appraisal	North Sea	Oil
PL 001 B	Ivar Aasen	34.8 %	Det norske	Appraisal	North Sea	Oil
PL 029 B	Gina Krog	3.3 %	Statoil Petroleum AS	Appraisal	North Sea	Gas
2016						
PL 554	Garantiana	30 %	Total E&P Norge	Wildcat	North Sea	Dry
PL 035	Madam Felle	50 %	Statoil Petroleum AS	Wildcat	North Sea	Oil
PL 035	Viti	50 %	Statoil Petroleum AS	Wildcat	North Sea	Dry
PL 001 B	Ivar Aasen	34.8 %	Det norske	Appraisal	North Sea	Oil
PL 035	Askja SE	50 %	Statoil Petroleum AS	Wildcat	North Sea	Oil
PL 001 B	Ivar Aasen	34.8 %	Det norske	Appraisal	North Sea	Dry
PL 035	Askja SE downflank	50 %	Statoil Petroleum AS	Appraisal	North Sea	Dry
PL 272	Beerenberg	50 %	Statoil Petroleum AS	Wildcat	North Sea	Gas / Condensate
PL 272	Slemmestad	50 %	Statoil Petroleum AS	Wildcat	North Sea	Gas / Condensate discovery
PL 442	Langfjellet	90.3 %	Det norske	Wildcat	North Sea	Oil

3.6 Non-operational Material Contracts

The Company has not entered into any material contracts outside the ordinary course of business during the last two years, other than the transaction agreement and related entered into for the purpose of the Transaction, see Section 4 "The Transaction", and the transaction agreements for the Company's other recent acquisitions referred to in Section 3.1 "—Introduction".

3.7 Significant Recent Trends

The Company's main production comes from the Alvheim area (the Alvheim, Volund, Vilje and Bøyla fields – all tied back to the Alvheim FPSO). As a result of early completion of the Viper and Kobra wells by the Transocean Winner rig, the Company was able to drill the top-hole sections of the next two Volund wells within the contracted rig slot in July 2016. This may allow the Company to complete these two wells earlier than originally planned, enabling earlier first oil. The Alvheim FPSO was shut down for planned maintenance from 5 to 19 August 2016.

The Atla, Enoch, Jette, Jotun and Varg fields also contribute to the Company's total production volumes in 2016 and these are sold on a term basis. The Varg field was shut down in June 2016. The Jotun and Jette fields are planned for shut down during Q4 2016.

Production of gas from the Alvheim, Jette, Jotun, Atla and Varg fields are sold on a term basis.

3.8 Capital Resources

Sources of Liquidity

The Company's principal sources of liquidity are operating cash flows from its producing assets. To the extent necessary, the Company is also able to utilize the undrawn capacity under its financing facilities to fund its liquidity needs. In addition to its operating cash flows, the Company relies on the debt capital markets for both short and long term funding. Currently, the Company has access to two syndicated bank facilities maturing over the next three to five years. Further, the Company has two outstanding bond issuances, maturing in four and seven years respectively. The Company's liquidity needs consist of funding operating expenses, changes in working capital, capital expenditures, debt service requirements and other liquidity requirements that may arise from time to time, including, without limitation, (i) refinancing of outstanding debt, (ii) acquisitions and other investment opportunities, (iii) exploration and development capital expenditure and (iv) payments in the ordinary course of business.

The Company prepares short-term (12 months) and-long term forecasts on a regular basis in order to plan the Company's liquidity requirements. These plans are updated regularly for various scenarios and form part of the decision basis for the Company's Board of Directors.

Some reporting requirements are also required under the Company's bank facilities, including quarterly updates of a revolving liquidity budget for the next 12 months and throughout the bank facility's maturity.

As of 30 June 2016, the Company had cash reserves of USD 68 million and undrawn facilities of USD 953 million.

See Section 8.6 "Selected Financial Information—Other Selected Financial Information" for certain relevant ratios and other unaudited non-IFRS key financial and operating information for the Company:

Funding and Treasury Policies

The Company actively monitors its financial risks with the objective of protecting the Company's business operations from adverse movements in such risks. The Company has in place policies for this management. Key risks and considerations are outlined below:

Foreign Exchange

Most of the Company's revenue is received in USD and GBP, whilst it has expenditures in several other currencies, predominantly in NOK, EUR and SGD. The Company manages this exposure through derivatives such as FX forwards and FX options.

Commodity Prices

Fluctuations in commodity prices, in particular Brent crude oil, affect the revenue of the Company. Whilst it has no mandatory hedging requirements, the Company manages this exposure through derivatives from time to time. Currently the Company has in place oil put options at a strike price of USD 55 for the remainder of 2016. No commodity hedging is in place from 2017 onwards.

Interest Rates

The Company is exposed to changes in the USD (LIBOR) and NOK (NIBOR) interest rates on its floating rate debt. Currently the Company has fixed the LIBOR interest rate for USD 400 million of its floating rate debt until the end of 2020. Further the Company's outstanding NOK Senior Unsecured Bond has been swapped into USD using a cross currency interest rate swap.

Funding

The Company's goal is to be fully funded for all its committed work program, both operational and development activities. For this, the Company aims to maintain a diversified funding base for its short - and long term financing requirements. In addition to its equity funding, the Company currently has in place credit facilities with two bank syndicates and it has issued two bonds in the debt capital markets. The maturities of its debt facilities are staggered over the next three to seven years. The Company's current credit facilities and bonds are further described in detail below.

Going forward, the Company will assess its capital structure with the aim to put in place a flexible and fit for purpose structure that reflects the new Company after the Transaction. Based on its size and robustness, it is the management's view that the Company should have good access to the capital market going forward.

The Company's Borrowing Arrangements

The Company is in discussions with its creditors with the aim of amending certain provisions in its financing agreements, including resolution to any current dividend restrictions. Further, the Company is in discussion with the syndicate for the Revolving Borrowing Base Facility for a potential increase in this facility as a result of the Transaction.

*Revolving Borrowing Base Facility ("**RBL**")*

On 8 July 2014, the Company entered into a USD 3 billion senior secured multi-currency revolving credit facility, subsequently amended by an amendment and restatement agreement dated 30 June 2015.

Amounts available under the RBL facility are further subject to a borrowing base limitation, which is re-determined semi-annually. As of 30 June 2016, the available amount under the RBL was USD 2.9 billion, of which the Company had drawn USD 2.4 billion. The facility may be used for general corporate purposes.

The interest payable is LIBOR plus a margin of 2.75% per annum. Certain fees are also payable, including, but not limited to: (i) a commitment fee on available commitments; (ii) a utilization fee calculated on the basis of aggregate outstanding utilizations; and (iii) a commission on letters of credit issued.

The RBL facility is currently secured by security interests over certain of the assets, including, but not limited to certain monetary claims, trade receivables and inventory, as well as certain participating interests in licenses of the Company for the exploration and production of oil and gas resources on the NCS.

The agreement contains provisions regarding events of default, as well as customary representations and warranties, subject to certain agreed exceptions and qualifications. Furthermore, the Company must ensure compliance with certain financial covenants to be calculated and satisfied in accordance with the terms therein, including, but not limited to:

- a maximum leverage ratio; and
- a minimum interest cover ratio

*Revolving Credit Facility ("**RCF**")*

On 30 June 2015, the Company entered into a USD 550 million senior secured multi-currency revolving credit facility. As of 30 June 2016, no amounts have been drawn on this facility. Interest payable is set at the relevant reference rate plus a margin. The margin is initially 4% and will be increased throughout the duration of the facility. The facility matures in July 2019, with the possibility of two one-year extensions, subject to the banks' approval. The facility may be utilised for general corporate purposes.

Certain fees are also payable, including, but not limited to: (i) an up-front fee, (ii) a commitment fee on available commitments; and (iii) a utilization fee calculated on the basis of aggregate outstanding utilizations.

The RCF is secured by security interests over certain of the assets of the Company, including, but not limited to certain monetary claims, trade receivables and inventory, as well as certain participating interests in licenses for the exploration and production of oil and gas resources on the NCS of the Company. The security interests rank with priority behind the RBL facility with right of succession.

The RCF facility is based on similar terms as the RBL, but without a borrowing base mechanism. The facility contains provisions regarding events of default, as well as customary representations and warranties, subject to certain agreed exceptions and qualifications. The facility contains the same financial covenants as in the RBL.

NOK Senior Unsecured Bond

In July 2013, the Company issued a NOK 1.9 billion unsecured bond loan with Nordic Trustee ASA as trustee. The loan carries interest at a rate equal to three month NIBOR plus 6.5% per annum. For the calculation of interest, NIBOR shall, if NIBOR falls below 1%, be deemed to equal 1%. The principal falls due on 2 July 2020 and interest is paid on a quarterly basis.

The proceeds of the NOK 1.9 billion bond issuance were used for general corporate purposes. On 1 April 2015, and subsequently on 27 May 2016, bondholder meetings were held in order to approve certain amendments to the bond agreement.

The NOK bond agreement does not permit the Company to prepay the NOK Bonds prior to maturity date. The bond is however repayable at the bondholder's request, at levels between 101% - 104%, upon the occurrence of certain change of control events or in the event that the Company issues certain forms restricted debts as defined in the loan agreement.

The agreement contains provisions regarding events of default, as well as customary representations and warranties, subject to certain agreed exceptions and qualifications. Further, the Company must ensure compliance with certain financial covenants to be calculated and satisfied in accordance with the terms therein, including, but not limited to:

- a maximum leverage ratio
- a minimum interest cover ratio; and
- a minimum liquidity covenant.

Subordinated Bond

In May 2015, the Company issued an unsecured, subordinated bond loan with Nordic Trustee ASA as trustee. The initial bond issue was USD 300 million, but the documentation allows the Company to increase the subordinated bond loan up to USD 500 million. The loan carries fixed interest at a rate equal to 10.25% per annum. The principal falls due on 27 May 2022 and interest is paid on a semi-annual basis. The proceeds of the subordinated bond loan were used for general corporate purposes.

Subject to the absence of certain events within certain periods prior to an interest payment date, the Company may elect to defer payment of interest due on such interest payment date. Deferred interest will carry interest at the prevailing interest rate for the bonds plus 2.00%.

The bond agreement contains redemption options to the issuer, including, but not limited to, redemption upon certain corporate restructuring events or a replacing capital event. These events will give the Company the right to redeem the bonds at 101% or 110% of par value. The bonds are repayable at bondholders' request, at 101% of par value with the addition of accrued interest, upon certain events constituting a change of control. The agreement contains provisions regarding events of default, as well as customary representations and warranties, subject to certain agreed exceptions and qualifications. The agreement does not contain any financial covenants.

Maturity Overview

The table below shows the contractual maturities of financial liabilities of the Group as of 30 June 2016.

USD thousands	Original Loan	Outstanding	Payments Due in Period			
Loan	**Amount**	**Principal**	**2016**	**2017**	**2018**	**2019—**
RBL..................................	3,000,000	2,395,000	0	0	600,000	2,400,000
RCF..................................	550,000	0	0	0	0	550,000
NOK Senior Unsecured Bond..............................	255,000[(1)]	255,000	0	0	0	255,000
Subordinated bond	300,000	300,000	0	0	0	300,000
Total................................	**4,105,000**	**2,950,000**	**0**	**0**	**600,000**	**3,505,000**

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(1) The NOK Senior Unsecured Bond has been swapped into USD using a cross currency interest rate swap. This amount reflects this swap.

Restrictions on the Use of Capital Resources

Each of the Company's financing facilities may be used for general corporate purposes. Some of the facilities place restrictions and prioritization of cash flows, including, but not limited to certain dividend restrictions.

Further, the financing facilities contain certain restrictions on the level of investments, which can be made outside the NCS.

3.9 Recent Developments

Other than as discussed below, there has been no significant change in the Group's financial and trading position since 30 June 2016:

- The Company is in discussions with its creditors with the aim of amending certain provisions in its financing agreements, including resolution to any current dividend restrictions. Further, the Company is in discussion with the RBL syndicate for a potential increase in this facility as a result of the Transaction.

- On 31 August 2016, the Company announced that drilling of exploration well 25/2-18 S on the Langfjellet prospect in the North Sea was about to be completed. The well encountered a gross oil column of 109 meters in the Vestland Group. A technical sidetrack was drilled to collect data and the well is currently being prepared for a sidetrack and welltest. Preliminary volume estimates for the discovery are in the range of 24 to 74 million barrels of oil equivalent. The licensees will evaluate the discovery with regards to a potential development together with other discoveries in the area. Following the successful drilling results at Langfjellet, the licensees have identified further prospectivity within the license. The Company is operator and holds a 90 percent working interest in PL442. LOTOS Exploration and Production Norge AS holds the remaining 10 percent.

3.10 Working Capital Statement

As of the date of this Information Memorandum, the Company is of the opinion that the working capital of the Group is sufficient for its present requirements.

3.11 Legal and Arbitration Proceedings

As of the date of this Information Memorandum, the Company is not subject to any governmental, legal or arbitration proceedings during the course of the preceding twelve months, including any such proceedings which are pending or threatened, of such importance that they have had in the recent past, or may have, a significant effect on the Company or the Group's financial position or profitability.

3.12 Board of Directors, Management and Corporate Governance

Board of Directors

The Company's Articles of Association provide that the Board of Directors shall have between five and ten members. In accordance with Norwegian law, the employees are entitled to elect up to one third, and at least two, of the members of the Board of Directors. The other directors are appointed by the Company's corporate assembly. In accordance with Norwegian law, the CEO and at least half of the members of the Board of Directors must either be resident in Norway, or be citizens of and resident in an EU/EEA country.

The members of the Board of Directors and their holdings of shares in the Company are presented in the table below.

	Position	Shares
Øyvind Eriksen	Chairman	–
Anne Marie Cannon	Deputy Chair	4,000
Kjell Inge Røkke[(1)]	Director	–
Kitty Hall	Director	–
Trond Brandsrud	Director	–
Kjell Pedersen	Director	4,000
Gro G. Kielland	Director	–
Terje Solheim	Director	1,198
Lone Olstad	Director	–
Bjørn Thore Ribesen	Director	20,000
Emil Brustad-Nilsen	Deputy Director	–
Aage Ertsgaard	Deputy Director	6,530
Kristin Gjertsen	Deputy Director	6,321
Ifor Roberts	Deputy Director	7,887

(1) The Company's largest shareholder, Aker Capital AS, is controlled by Aker ASA, which in turn is controlled by Kjell Inge Røkke and his family through TRG Holding AS and The Resource Group AS.

The Company's Corporate Assembly will appoint new members to the Board of Directors that will enter into effect at completion of the Transaction. The meeting of the Corporate Assembly is scheduled to be held on 28 September 2016. The Company's Nomination Committee has proposed that the following members are appointed to the Board of Directors: Bernard Looney, Chief Executive Upstream in BP and Kate Thomson, Group Head of Tax in BP.

The composition of the Company's Board of Directors is currently in compliance with the independence requirements of the Norwegian Code of Practice for Corporate Governance of 30 October 2014 (the **"Corporate Governance Code"**). The Corporate Governance Code provides that a board member is generally considered to be independent when he or she does not have any personal, material business or other contacts that may influence the decisions he or she makes as a board member.

Among the shareholder-elected board members, two (Øyvind Eriksen who is the CEO of Aker ASA, and Kjell Inge Røkke) are affiliated with the Company's largest shareholder Aker Capital AS. In addition deputy director Emil Brustad-Nilsen is an Investment Manager in Aker ASA. Deputy Chair Anne Marie Cannon was elected member of the Board of Directors for Aker ASA in April 2015. All other board members are considered independent of the Company's main shareholder, as well as of the Company's material business contacts. All board members are considered independent of the Company's executive personnel.

Corporate Assembly

Pursuant to the Norwegian Public Limited Liability Companies Act, two-thirds of the members of the Corporate Assembly and deputy members shall be elected by the general meeting by simple majority. One-third of the members of the Corporate Assembly and deputy members are elected by and among the employees. A majority of the employees or trade unions representing two-thirds of the employees may, in addition, decide that observers and deputy members are to be elected. The number of observers may be up to half the number of employee members of the Corporate Assembly. Pursuant to the Company's Articles of Association, the Corporate Assembly shall have twelve members and up to eight deputy members. Eight members and up two four deputy members shall be elected by the General Meeting. Four members and the four corresponding deputy members shall be elected by and among the employees. The chairman of the Corporate Assembly is elected by the Corporate Assembly.

The members of the Corporate Assembly and their holdings of shares in the Company are presented in the table below.

	Position	Shares
Sverre Skogen	Chairman	–
Ole Jakob Hundstad	Member	–
Anne Grete Eidsvig	Member	–
Odd Reitan	Member	–
Finn Berg Jacobsen	Member	–
Leif O. Høegh	Member	–
Olav Revhaug	Member	–
Jens Johan Hjort	Member	–

Kristin Grønn	Member	48
Ståle Haverstadløkken	Member	10,033
Hege Jarstø...	Member	490
Tor Kristian Hals	Member	—

It is proposed by the Company's Nomination Committee that the Extraordinary General Meeting of the Company to be held on 28 September 2016 appoints Murray Auchincloss as a new member of the Corporate Assembly in place of Odd Reitan, and that the appointment will take effect from completion of the Transaction.

Management

The Company's executive management (the "**Management**") consists of eight individuals. The members of the Company's Management and their holdings of Shares in the Company are set out in the table below.

	Position	Shares
Karl Johnny Hersvik	CEO	—
Per Harald Kongelf	SVP Improvement	—
Olav Henriksen	SVP Projects	—
Alexander Krane	CFO	12,000
Leif G. Hestholm..	SVP HSEQ	—
Gro G. Haatvedt	SVP Exploration	8,000
Geir Solli..	SVP Operations	25,000
Tommy Sigmundstad	SVP Drilling and Well	

Benefits upon Termination of Employment

None of the members of the Board of Directors or the Corporate Assembly have contracts providing benefits upon termination of their positions as Board Members.

The members of the Management have contracts entitling them to six months' severance pay upon termination of contract.

Nomination Committee

The Company's Articles of Association provide for a Nomination Committee composed of minimum three members who are elected by the General Meeting for two-year terms. The Nomination Committee is responsible for nominating the shareholder-elected members of the Board of Directors and to make recommendations for remuneration to the members of the Board of Directors. The current members of the Nomination Committee are Arild S. Frick (chairman), Hilde Myrberg and Finn Haugan.

Audit and Risk Committee

The Company has an Audit and Risk Committee comprising of three members elected by and among the member of the Board of Directors. The current members of the Audit and Risk Committee are Trond Brandsrud (chairman), Anne Marie Cannon and Gro Kielland.

Remuneration Committee

The Company has a remuneration committee of three members elected by and among the Board of Directors. The current members of the remuneration committee are Øyvind Eriksen (chairman), Kjell Pedersen and Terje Solheim.

Corporate Governance

The Company's corporate governance principles are based on, and comply with, the Corporate Governance Code other than as disclosed in the Company's corporate governance statement for the year ended 31 December 2015 set forth on page 48 of the Company's 2015 Annual Report which is incorporated by reference in this Information Memorandum; see Section 10 "Incorporation by Reference; Documents on Display".

The business address of the Board of Directors, Management and Supervisory Bodies

The Company's registered business address, Munkegata 26, 7011 Trondheim, Norway, serves as c/o address for both the members of the Board of Directors, Management and the other Supervisory Bodies in relation to their functions in the Company.

3.13 Corporate Information and Share Capital

Incorporation, Company Registration Number, Registered Office and Other Company Information

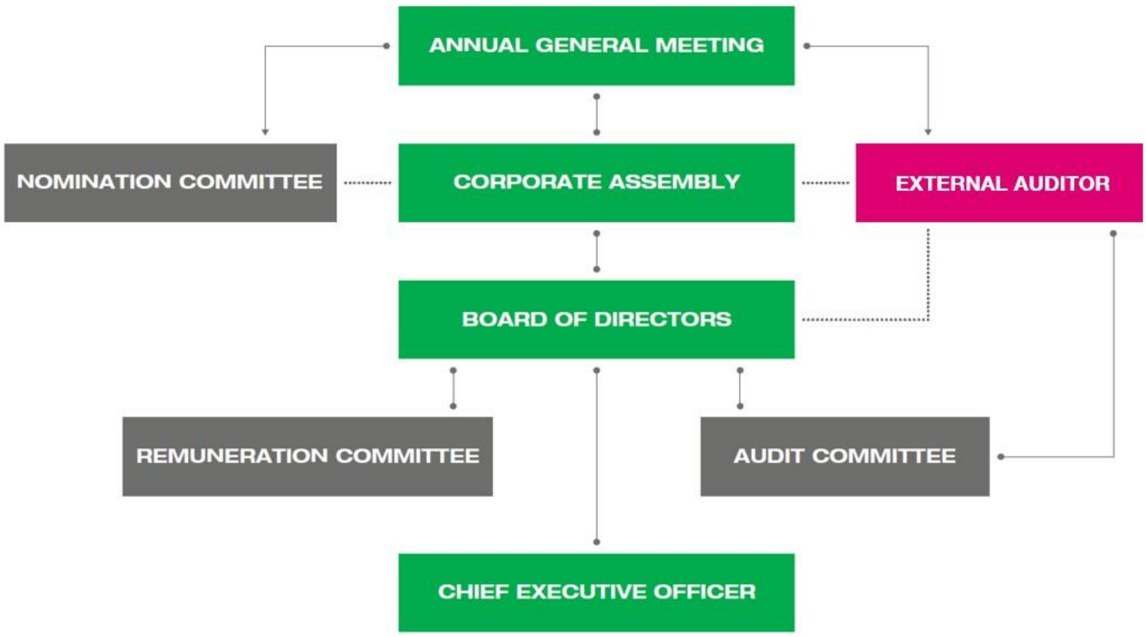
Det norske oljeselskap ASA is a Norwegian public limited liability company incorporated under the laws of Norway and in accordance with the Norwegian Public Limited Companies Act of 13 June 1997 no. 45 with company registration number 989 795 848. The Company was incorporated on 9 May 2006.

The Company has its head office and registered address at Munkegata 26, 7011 Trondheim, Norway, its telephone number is +47 90 70 60 00, and its website is www.detnor.no.

As of 30 June 2016, the Company does not have any material subsidiaries. Det norske Exploration AS (previously Svenska Petroleum Exploration AS) and Det norske oil AS (previously Premier Oil Norge AS) were liquidated following the transfer of their activity to the Company in Q4 2015 and Q1 2016 respectively. The Company currently has three subsidiaries, Alvheim AS, Det norske oljeselskap AS (previously Marathon Oil Norge AS) and Sandvika Fjellstue AS, which are immaterial for consolidation purposes and which will therefore not be described in detail in this Information Memorandum.

Governance Structure

The Company's governance structure is set out in the diagram below.



Trading Market for the Shares and Trading Symbol

The shares of the Company are admitted to trading on the Oslo Stock Exchange and trade under the trading symbol "Det norske" with the ticker "DETNOR".

International Securities Identification Number (ISIN) and Shareholders' Register

The Company's Shares are registered in book-entry form with the VPS under the International Securities Identification Number ("**ISIN**") NO0010345853. The Company's register of shareholders with the VPS is administrated by DNB Bank ASA, Registrars Department, Dronning Eufemias gate 30, N-0191 Oslo, Norway.

Share Capital

As of the date hereof, the Company's share capital is NOK 202,618,602 divided into 202,618,602 shares with each share having a par value of NOK 1.00. Upon completion of the Transaction, the Company's share capital will be NOK 337,737,071 divided into 337,737,071 Shares, with each Share having a par value of NOK 1.00. All the existing Shares have been created under the Norwegian Public Limited Companies Acts, and are validly issued and fully paid. The Company has one class of shares.

Share Capital History

On 5 August 2014, the Company carried out a share capital increase under a rights issue (Nw. *fortrinnsrettsemisjon*) whereby the share capital was increased by NOK 61,911,239, from NOK 140,707,363 to NOK 202,618,602, by issue of 61,911,239 new shares, each with a par value of NOK 1.00. The subscription price in the rights issue was NOK 48.50 per share.

Apart from this, there have been no changes in the Company's share capital for the period from 1 January 2013 and up to the date of this Information Memorandum.

Notifiable Holdings

As of 6 September 2016, which was the latest practicable date prior to the date of this Information Memorandum, and insofar as known to the Company, the following persons had, directly or indirectly, interest in 5% or more of the issued share capital of the Company (which constitutes a notifiable holding under the Norwegian Securities Trading Act):

	Number of Shares	Holding (%)
Aker Capital AS	101,289,038	49.99%
Folketrygdfondet	15,994,830	7.89%

BP will subscribe for 135,118,469 shares in the Company at closing for a subscription price of NOK 80 per share. BP has agreed to sell the right to have issued 33,809,168 of these shares to Aker Capital AS at closing for a cash consideration of NOK 80 per share.

Following completion of the Transaction, Aker Capital AS will be the owner of 135,098,206 shares (constituting approximately 40% of the Company's share capital at such time), and BP Global Investments Ltd (once an internal sale and repurchase is completed) will own a total of 101,309,301 shares (together constituting approximately 30% of the Company's share capital at such time). Other shareholders will hold a total of 101,329,564 shares representing approximately 30% of the Company's share capital.

3.14 Independent Auditor

The Company's independent auditor is KPMG AS, which has its registered address at Sørkedalsveien 6, 0369 Oslo, Norway and has audited the Company's separate and group financial statements for 2014 and 2015, which are incorporated by reference in this Information Memorandum. The partners of KPMG AS are members of The Norwegian Institute of Public Accountants (Nw. *Den Norske Revisorforening*).

Ernst & Young AS was the Company's statutory auditor from 2010 to 2013, and has audited the Company's financial statements for 2013 which are incorporated by reference in this Information Memorandum. EY's address is Dronning Eufemias gate 6, Oslo Atrium, P.O. Box 20, 0051 Oslo, Norway. The partners of Ernst & Young AS are members of The Norwegian Institute of Public Accountants.

3.15 Legal Advisor

Advokatfirmaet BA-HR DA, Tjuvholmen allé 16, 0252, Oslo, Norway has acted as legal counsel (as to Norwegian law) to the Company in connection with the Transaction.

4. THE TRANSACTION

This Section provides information on the background and reasons for the Transaction as well as a discussion of certain related arrangements and agreements entered into or to be entered into in conjunction with the Transaction.

4.1 Overview

Through the Transaction the Company will acquire 100% of the shares in BP Norge, against issuance of new shares in the Company to the Sellers and a cash consideration as further described in Section 4.5 “Consideration” below. BP Norge is today a wholly owned subsidiary of BP plc, and holds all of the BP group’s interests in exploration and production licenses on the NCS. BP, through legacy company Amoco, has been involved in E&P activities in Norway since the beginning of the Norwegian oil and gas industry. The business of BP Norge was merged with the business of Amoco in Norway in 1998. The BP Group’s downstream activities in Norway do not form part of the Transaction.

4.2 Background and Reason for the Transaction

The Company and BP Norge are both key players on the NCS. By combining the two entities the parties wish to establish a leading independent E&P company in Norway. The combined company will have significant current production output, a strong reserve and resource base, and attractive growth opportunities going forward. The Company intends to combine and develop the best resources of both entities, and create a new innovative, cost efficient E&P company for the future. Aker Capital AS and the Sellers will from the start be the two largest shareholders in the combined entity, which will be renamed “Aker BP ASA” at closing of the Transaction.

4.3 The Sellers

The Sellers are both wholly owned subsidiaries within the BP Group. The BP Group is one of the leading integrated oil and gas companies worldwide based in London, UK. The shares of the parent company BP plc are listed on the London Stock Exchange and the New York Stock Exchange.

4.4 Description of the Transaction

Through the Transaction the Company will acquire 100% of the shares in BP Norge against the issuance of new shares in the Company and a cash consideration as further described in Section 4.5 "Consideration" below.

The Company will acquire the shares in BP Norge on «as is» terms, with certain limited warranties and indemnities from BP relating to *inter alia* ownership and title to the shares, tax, and certain other matters. The Transaction is otherwise based on a merger principle without subsequent adjustments between the parties. The Transaction will have economic effect between the parties from 1 January 2016, so that the Company will have the economic interest in the business of BP Norge from and including 1 January 2016 if the Transaction is completed.

BP Norge is a limited liability company incorporated in Norway with its main office in Stavanger, Norway. The company is a wholly owned subsidiary of the BP Group.

The management of BP Norge in Norway consists of managing director Jan Norheim, S&OR manager Einar Haaland, wells manager Øystein Eide, resource manager Grete Block Vagle, vice president operations Norway Eldar Larsen, director external relations & communication Olav Fjellså, managing council Christen Minos, programme project general manager Norway cat B projects Duncan Macleod, procurement & supply chain management country manager Rolf Nystein, planning & commercial manager Norway Andrew McNeill and human resources manager Kåre Ekroll.

The chairman of the board of directors of BP Norge is Peter James Mather. The other directors are Jan Norheim, Kåre Ekroll, Mark Thomas, Christen Minos, Ørjan Holstad, Christine Eikeberg and Ingard Haugeberg.

BP Norge is focused on upstream oil and gas activities in Norway, and is the operator of the producing fields Valhall, Hod, Ula, Tambar and Skarv. BP Norge also participates in several other licenses on the NCS.

In 2015, the total revenues for BP Norge were NOK 7.93 billion and the net operating result was a loss of NOK 0.83 billion. Total balance sheet assets were NOK 23.54 billion (all of the foregoing in rounded numbers, for further accounting information see Section 10 “Selected financial information for BP Norge AS”).

BP Norge has no external financial debt other than working capital. All internal intercompany debt will be settled by the Sellers prior to closing the Transaction.

The Company has agreed to change its corporate name to “Aker BP ASA” with effect from closing of the Transaction. The Company will enter into licensing agreements with the Aker group and the BP Group for the right to use the Aker name and the BP name respectively.

4.5 Consideration

The subscription price for the new shares shall be settled by way of set off against receivables corresponding to the subscription amount. The receivables will arise as consideration for Amoco Norway Oil Company transferring 520 shares in BP Norge to the Company and by BP Global Investments Ltd transferring 480 shares in BP Norge to the Company, in total 1 000 shares representing 100% of the share capital in BP Norge.

The transfer of the shares in BP Norge and set-off of the resulting accounts receivable shall be settled at completion of the transaction agreement between the Company, Amoco Norway Oil Company, BP Global Investments Ltd and BP Exploration Operating Company Limited dated 10 June 2016, which will take place in the offices of Advokatfirmaet BA-HR DA, Tjuvholmen Allé 16, Oslo.

In consideration the Sellers will receive and account receivable which will be converted into 135,118,469 Shares in the Company (the "**Consideration Shares**") for a subscription price of NOK 80 per share, plus a cash consideration of USD 242,523,406 (including working capital adjustment) plus interest of 4.35% per annum calculated from and including 1 January 2016 to and including the date of closing of the Transaction.

The Sellers will at closing sell the right to have issued 33,809,168 of the Consideration Shares to Aker Capital AS for a price corresponding to the subscription price of NOK 80 per share.

As a result the Sellers will own 101,309,301 shares in the Company immediately following closing of the Transaction, representing approximately 30% of the total share capital and Aker Capital AS will own 135,098,206 shares representing approximately 40% of the total share capital. All shares will carry the same rights and will rank pari passu with the existing issued shares of the Company. All shares will be listed on the Oslo Stock Exchange.

4.6 Financing Arrangements in Connection with the Transaction

The Company will issue new shares and pay cash in consideration for the shares in BP Norge. The cash consideration will be settled by existing cash holdings and available loan facilities. No other external financing is therefore required for the completion of the Transaction.

4.7 Conditions for Closing of the Transaction

The Transaction is subject to customary conditions precedent to closing, including approvals from the MPE and the Ministry of Finance (the "**MoF**") and the agreed equity injection into BP Norge of USD 340,000,000. The approval from the MPE was obtained on 26 August 2016. The Transaction is also subject to required approvals by the General Meeting of the Company with a 2/3 majority support from the shareholders who participate. Aker Capital currently controls approximately 49.9% of the shares in the Company and has committed to vote in favour of the Transaction. The Company' second largest shareholder, Folketrygdfondet, has also stated that they will support the Transaction. The General Meeting is scheduled to be held on 15 September 2016.

4.8 Relationship with Creditors

The Company will significantly strengthen its balance sheet as a result of the Transaction and expects to renegotiate the terms of some of its current financial arrangements to enable the Company to make dividend payments subject to renegotiated covenants and dividend restrictions.

4.9 Closing of the Transaction

The Company expects that the conditions for closing will be satisfied within the end of September 2016 and that completion will occur on or around 30 September 2016. The consideration shares will be listed shortly thereafter.

4.10 Agreements with Members of the Board of Directors and Management in Connection with the Transaction

There are no special agreements or arrangements with the members of the board of directors or the management in connection with the Transaction.

Aker Capital AS and the Sellers have entered into an agreement in connection with the transfer of the right of have issued shares from the Sellers to Aker Capital AS. Pursuant to this agreement, the parties shall support proportionate board representation for both Aker and BP as long as they remain significant shareholders in the Company. The parties have agreed to support that Øyvind Eriksen shall continue as Chairman and Karl Johnny Hersvik as CEO in the Company. The parties shall also support the right for BP to nominate one member of the Corporate Assembly.

Aker Capital and the Sellers aim to introduce a quarterly dividend policy, including a first dividend payment for the fourth quarter of 2016.

4.11 Accounting and Tax Matters - Tax Consequences of the Transaction for the Company

The Transaction is not expected to create material tax consequences for the Company. The business of BP Norge and the Company is expected to be combined into one single legal entity with tax effect from 1 January 2016 and thereby be consolidated for tax purposes.

4.12 Allocation of Expenses Relating to the Transaction

Each of the Company and the Sellers will bear their own expenses in connection with the Transaction.

4.13 Resolution to Issue the Consideration Shares

The Board of Directors of the Company has proposed that the extraordinary general meeting of the Company to be held on 15 September 2016 shall pass the following resolution for the issue of the Consideration Shares:

(a) The Company's share capital is increased by NOK 135 118 469 by issuing 135 118 469 new shares each with a nominal value of NOK 1.

(b) The subscription price is NOK 80 per share.

(c) Amoco Norway Oil Company, address Corporation Trust Center, 1209 Orange Street, Wilmington DE 19801, USA, is given the right to subscribe for 70 261 604 shares.

(d) BP Global Investments Ltd, address Chertsey Road, Sunbury on Thames, Middlesex TW16 7BP, United Kingdom, is given the right to subscribe for 64 856 865 shares.

(e) The time limit for subscribing the new shares is 1 December 2016.

(f) The subscription price for the new shares shall be settled by way of set off against receivables corresponding to the subscription amount. The receivables will arise as consideration for Amoco Norway Oil Company transferring 520 shares in BP Norge AS to the Company and by BP Global Investments Ltd transferring 480 shares in BP Norge AS to the Company, in total 1 000 shares representing 100% of the share capital in BP Norge AS.

(g) The transfer of the shares in BP Norge and set-off of the resulting accounts receivable shall be settled at completion of the transaction agreement between the Company, Amoco Norway Oil Company, BP Global Investments Ltd and BP Exploration Operating Company Limited dated 10 June 2016, which will take place in the offices of Advokatfirmaet BA-HR DA, Tjuvholmen Alle 16, Oslo. Completion is expected to take place on or around 30 September 2016.

(h) The right to have issued the new shares can be transferred before the share capital increase has been registered.

(i) Simultaneously with the issuance of the new shares the Company shall pay a cash consideration to Amoco Norway Oil Company and BP Global Investments Ltd in a total amount of USD 242 523 406 plus interest of 4,35% p.a. that will accrue from and including 1 January 2016 to and including the date of completion of the share transfer. The cash consideration shall be divided so that 52% is paid to Amoco Norway Oil Company and 48% is paid to BP Global Investments Ltd in accordance with the number of shares in BP Norge transferred by each party to the Company.

(j) For the further description of the share contribution and the transaction agreement reference is made to the auditor's statement included in attachment 1, cf. the public limited companies act section 10-2(3), and to the board explanation for the proposal to increase the share capital.

(k) The new shares will carry full rights in the Company, including the right to receive dividend, from and including the time of registration of the share capital increase in the Norwegian Register of Business Enterprises. From the same point in time § 4 of articles of association are amended to read as follows: «The Company's share capital is NOK 337 737 071 fully paid-up and divided between 337 737 071 shares, each with a nominal value of NOK 1. The Company's shares shall be registered in the Norwegian Central Securities Depository.

(l) The estimated costs of the share capital increase are USD 100.000.

The Consideration Shares are expected to be issued on or about 30 September 2016 and are expected to be listed on the Oslo Stock Exchange under the ticker code "DETNOR" or new ticker code for the Company on or about the same date. The Consideration Shares will be freely tradable and registered under the Company's ordinary ISIN NO0010345853.

4.14 Significance and Effects for the Company Following the Transaction

The Transaction will position the Company as a leading player on the NCS, with significant operatorships, current production and strong operating cash flow. The Company will have a strong balance sheet, which is expected to enable the Company to make dividend payments from the accounting year 2016 (subject to amendment to the current loan agreements) and position it for further growth, assuming the Company's current market outlook and subject to risk factors.

5. PRESENTATION OF BP NORGE AS

This Section provides an overview of the business of BP Norge 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" on page 1. You should read this Section in conjunction with the other parts of this Information Memorandum, in particular Section 1 "Risk Factors" and Section 6 "The Company Following the Transaction".

5.1 Introduction

BP Norge is a Norwegian private limited liability company incorporated under the laws of Norway and in accordance with the Norwegian Private Limited Liability Companies Act of 13 June 1997 no. 45 with company registration number 981 355 210. The company was incorporated on 30 June 1999.

BP Norge has its head office and registered address at Godesetdalen 8, 4034 Stavanger, Norway and its website is www.bp.no, with telephone number +47 52 01 30 00.

The origins of BP Norge began with Amoco that operated in Norway from 1965 and later became BP Amoco post the BP Amoco merger and then later BP Norge. Amoco applied for blocks in the first licensing round on the NCS and was awarded license 006, blocks 2/5 and 2/8 that later became the Valhall field. The company currently holds 13 production licenses, 12 of which it serves as operator. Six of the production licenses are producing fields. One of the production licenses (PL 712) is in the process of being relinquished to the Norwegian state. BP Norge operates 13 platforms and one FPSO with storage and offloading capacity.

As per the 2015 BP Norge Annual Accounts petroleum income amounted to NOK 7,899 million, operating cash flow amounted NOK 3,252 million with net income for the year NOK -301 million. The total assets on the balance sheet amounted to NOK 23,537 million and equity amounted to NOK 3,704 million. There are no significant assets or liabilities not on the balance sheet. FY15 production was net 62.2 mboed and 1H16 production was net 57.0 mboed.

BP Norge operates from its office in Stavanger. As of June the company employed 864 employees. Out of the 864 employees, 429 are offshore and 435 are local onshore staff.

The board of directors in BP Norge currently consists of 11 members. Peter James Mather currently serves as chairman. The other board members are Jan Jakob Norheim, Kåre Ottar Ekroll, Mark Joseph Thomas, Christen Iben Tollefsen Minos, Ørjan Holstad, Christine Elisabet Eikeberg and Ingard Haugeberg. The deputy board members are Thor Inge Bollestad, Sølvi Bergstuen and Ann Sesilie Eriksen Tekfeldt. Jan Jakob Norheim is the Managing Director of BP Norge.

BP Norge has obtained a report on “Reserves and Contingent Resources for Certain Properties offshore Norway for BP Norge AS” from DeGolyer and MacNaughton, attached hereto as Appendix B “Expert Opinion”. DeGolyer and MacNaughton provides reserves consulting services, resources evaluations, field studies, reservoir simulation studies, and many other services for energy and financial services companies worldwide. The company employs more than 150 professional petroleum engineers, geologists, petrophysicists, statisticians and energy economists. The company has its primary place of business in Dallas with the following address: DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244. DeGolyer and MacNaughton has no interest in the Company.

Per year-end 2015, BP Norge’s 2P *(P50)* reserves were estimated to be 297 million barrels of oil equivalent («mmboe») and matured 2C *(best)* contingent resources of 114 mmboe, based on sales gas. The BP Norge’s 2P *(P50)* reserves based on marketable gas (sales gas plus fuel gas) are estimated to 306 mmboe. Note that the 2P *(P50)* reserves are higher than reserves reported by the Norwegian Petroleum Directorate, primarily due to differences in reserves classification criteria.

5.2 Field Interests

BP Norge is currently operating five producing fields; Ula, Tambar, Valhall, Hod and Skarv.

The Ula field lies in Block 7/12, the Tambar field lies in Blocks 1/3 and 2/1, the Valhall field lies in Blocks 2/8 and 2/11, the Hod field lies in Block 2/11 and the Skarv field lies in Blocks 6507/2, 6507/3, 6507/5 and 6507/6.

Below is an overview of the field interests in the petroleum fields which BP Norge participates in:

Company	Ula	Tambar	Tambar Øst Unit	Valhall Unit	Hod	Skarv Unit
BP Norge AS	80%	55%	46.2%	35.953130%	37.5%	23.8350%
DONG E&P Norge AS	20%	45%	43.24%	-	-	-
Repsol Norge AS	-	-	9.76%	-	-	-
Kufpec Norway AS.....................	-	-	0.8%	-	-	-
Hess Norge AS..........................	-	-	-	64.046880%	62.5%	-
Statoil Petroleum AS..................	-	-	-	-	-	36.1650%
DEA Norge AS...........................	-	-	-	-	-	28.0825%
PGNiG Upstream International AS...	-	-	-	-	-	11.9175%

5.3 Key Assets

Producing Licenses

Ula (PL 019, PL 019B)

Ula is an oil field located in the southern part of the Norwegian sector of the North Sea. The water depth in the area is approximately 70 meters. The field was discovered in 1976 and production started in 1986, with BP Norge as operator.

The main reservoir is located at 3345 meters in the Ula formation in the Upper Jurassic.

FY15 production was net 7.2 mboed and 1H16 production was net 7.5 mboed.

Ula has successfully established itself as a regional processing hub with Tambar, Blane and Oselvar fields tied back.

The Ula development consists of three conventional bridge linked steel installations for production, drilling and accommodation. The Ula drilling rig was upgraded and recertified in 2013. During 2015 an extensive well work operation was completed to restore production from one of the main producers. Further planning and evaluation is on-going for a potential replacement well drilling programme during 2018 or 2019. The gas capacity at Ula was upgraded in 2008 with a new gas process and gas injection module (UGU), doubling the capacity. The total capacity of the gas compression is now 120 million standard cubic feet per day.

In 2015 a new flare tower was installed at Ula and a new fire and gas system was installed on the production platform.

In addition to the Tambar field the third party Blane and Oselvar fields are also tied back to Ula. The production is processed at Ula with liquids being exported through the Ekofisk system and gas re-injected into the Ula reservoir to increase Ula recovery. The Repsol Norge AS operated Blane field commenced production in 2007 and the Dong E&P Norge AS operated Oselvar field commenced production in 2009.

In 2015 the licensees in production license 405 decided to develop the discovery 8/10-4 S with a tie-back to Ula. The discovery has since been renamed “Oda”. The final investment decision is expected to be made in Q4 2016. The gas produced from Oda will be injected into the Ula reservoir and is expected to increase Ula oil production.

Ula oil and liquids, and liquids co-mingled with third party tie-in volumes, are transported by pipeline via Ekofisk to Teesside in the UK. All gas (from Ula and third party tie-ins) is re-injected into the reservoir to increase Ula oil recovery. BP Norge has 100% equity in the Ulapipe which is the oil and liquids export between Ula and Ekofisk. The Ula concession period currently expires in 2028. The resource potential extends beyond the concession period. There is a track record across the industry of achieving extensions to concessions, and subject to an extension being granted the cessation of production will be subject to the technical life of the facilities and the economic cut-off.

BP Norge holds an 80% interest in the license and is the operator. The other license partner is DONG E&P Norge AS holding a 20% interest.

Tambar (PL 065)

The Tambar field is located 16 km southeast of Ula. It is a normally unmanned wellhead platform, remotely controlled from Ula. The water depth in the area is approximately 68 meters. The field was discovered in 1983. Operated by BP Norge, Tambar started producing via Ula in Q3 2001.

Tambar has accommodation facilities for up to 12 persons. The production is piped to Ula for processing and export. The gas is injected into the Ula reservoir and oil is exported via Ekofisk to Teesside in the UK.

FY15 production was net 3.0 mboed and 1H16 production was net 2.6 mboed; this includes production from the Tambar East field.

Tambar has a multiphase pump (MPP) to reduce the wellhead pressure and enhance oil recovery. Planning for an artificial gas lift project including further development drilling is well advanced.

The Tambar concession period currently expires in 2021. The Tambar facilities were recently granted life extension until 2021 (the original design life expired in December 2016) and the cessation of production will be subject to the technical life of the facilities and the economic cut-off.

BP Norge holds a 55% interest in the license and serves as operator. The other license partner is DONG E&P Norge AS holding a 45% interest.

Tambar Øst (PL 019B, PL 065, PL 300)

Tambar Øst (East) is located just a few kilometers away from Tambar. It was discovered in 2007 and is located at a depth of 4,200 meters deep in the Late Jurassic Formation. The field has been developed with a production well from Tambar's main facility. Production started 2 October 2007.

BP Norge holds a 46.2% interest in the unit and serves as operator. The other unit partners are DONG E&P Norge AS holding a 43.24% interest, Repsol Norge AS holding a 9.76% interest and Kufpec Norway AS holding the remaining 0.8% interest.

Valhall (PL 006, PL 006B, PL 033B)

Valhall is a giant oil field located in the southern part of the Norwegian sector of the North Sea. The field was discovered in 1975 and production began in 1982. The water depth in the area is approximately 70 meters.

Valhall produces from Cretaceous rocks in the Tor Formation and the Hod Formation of the Late Cretaceous age. The reservoir is located at about 2400 meters. The chalk in the Tor Formation is heavily fractured.

FY15 production was net 19.2 mboed and 1H16 production was net 14.1 mboed.

Valhall also processes the production from the Hod field, currently produced through wells drilled from the South Flank unmanned Well Wead Platform.

The bridge linked Valhall complex currently consists of six separate steel platforms:

- The original Quarters Platform (QP), Drilling Platform (DP) with 30 well slots, Production and Compression Platform (PCP), now in cold storage, brought into service in 1981.
- The Wellhead Platform (WP with 19 well slots) installed in 1996.
- The Drilling and Water Injection Platform (IP with 24 slots). The platform configuration allows for the rig to be used for drilling and well maintenance on WP in addition.
- The integrated Production and Hotel platform (PH). The new platform was brought on stream in 2013 and replaces the original PCP and QP facilities. Power is supplied from shore through a 78MW power cable from Lista.

In addition the Valhall field has two unmanned Flank platforms, one in the south and one in the north, both approximately 6 km from the field centre. The Flank platforms are tied back to Valhall central complex where production is process and exported.

Oil and NGL is piped via Ekofisk to Teesside in the UK and gas is transported through the Norpipe pipeline to Emden in Germany.

The Valhall partners also own the 2/4 G platform which was installed in 1982. The platform is located on the ConocoPhillips operated Ekofisk field. 2/4G was the Valhall riser platform at Ekofisk but ceased production in 1998. The 2/4G bridge linking to Ekofisk was removed in 2014 and the 2/4G topside was removed in June 2016.

The Valhall license has a decommissiong programme underway; planning has started for decommissioning and the removal of the DP, QP and PCP platforms. Plugging and abandonment of DP wells started in 2014.

The Valhall concession period currently expires in 2028[1]. The resource potential extends beyond the concession period, there is track record across the industry of achieving extensions to concessions, and the cessation of production will be subject to the technical life of the facilities and the economic cut-off. The current design life for the new PH is 2049, ~2033 for IP and the Flank North and South, and WP was recently granted life extension until 2028.

BP Norge holds a 35.953125% interest in the unit and serves as operator. The other license partner is Hess Norge AS holding a 64.046875% interest.

Hod (PL 033)

Hod is an oil field in the southern part of the North Sea. The field was discovered in 1974. Hod is located 13 kilometres south of Valhall, and the water depth in the area is approximately 72 meters.

The Hod wellhead platform is remotely controlled from Valhall. The platform was the North Sea's first unmanned platform when production started in August 1990. The NUI ceased production in 2013 and the 8 NUI wells are currently shut-in waiting permanent plugging and abandonment. The Hod "saddle" area of the field continues to produce through wells drilled from the Valhall South Flank platform.

FY15 production was net 0.5 mboed and 1H16 production is net 0.5 mboed.

The Hod production license originally expired in 2015, but was extended until 2021 subject to progression and submittal of a PDO for further development of the Hod field before 2021. The extension includes commitment to acquire further seismic data in 2017, a decision on appraisal well, and a decision to enter Concept Development (BOK) by the end of 2017. An abandonment plan and an environmental impact assessment plan were submitted to the MPE in 2015. Approval of the decommissioning plan is expected during 2016 for the old Hod facilities. The Hod concession period currently expires in 2021[2], subject to the extension in the event of further development activity being proposed and approved. BP Norge holds a 37.5% interest in the license and serves as operator. The other license partner is Hess Norge AS holding a 62.5% interest.

Skarv (PL 159, PL 212, PL 212B, PL 262)

Skarv is located in the Norwegian Sea approximately 210 km from Sandnessjøen at 350-450 meter depth. The field was discovered in 1998 and began production in December 2012.

The Skarv field is developed with a production ship with storage and offloading capacity (FPSO) anchored to the seabed. The FPSO has a life expectancy of 25 years.

Production from the Skarv field represents a significant proportion of BP Norge's production. FY15 production was net 32.3 mboed and 1H16 production is net 32.3 mboed.

Maximum oil production was about 85,000 barrels per day gross at its peak and is currently around 42,500 barrels per day gross.

BP Norge holds an office for operational support and subsea warehouse at Horvnes supply base in Sandnessjøen.

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[1] Source BP NORGE AS Annual Accounts 2015
[2] Source BP NORGE AS Annual Accounts 2015

The Skarv consession period currently expires in 2033 and the original Skarv FPSO design life is 2035. The resource potential extends beyond the concession period, there is track record across the industry of achieving extensions to concessions, and the cessation of production will be subject to the technical life of the facilities and the economic cut-off.

BP Norge holds a 23.8350% interest in the unit and serves as operator. The other unit partners are Statoil Petroleum AS holding a 36.1650% interest, DEA E&P Norge AS holding a 28.0825% interest and PGNiG Norge AS holds the remaining 11.9175% interest.

Development Projects

The most material on-going development projects are the Snadd Development in the Skarv license and the West Flank Development in the Valhall license and a seven well infill drilling program on Valhall.

Snadd is a separate field within the Skarv unit. The concept development decision for the Snadd Development was made in 2Q 2016 and subject to continuing joint venture and regulatory support this could lead to PDO submission in 2H 2017.

The West Flank Development will develop the western flank of the giant Valhall field. The concept development decision for the West Flank Development is expected in 4Q 2016 and subject to continuing joint venture and regulatory support could lead to PDO submission in late 2017. It is also expected that Valhall infill drilling will start with a seven well infill drilling programme. This is due to commence in early 2017 following upgrade and recertification of the IP drilling rig.

The potential future third party tie-in to Ula platform from nearby field Oda will be tied-back to Ula. Oda took the decision to tie-back to Ula in 2015 and the final investment decision is due 4Q 2016. The intent is for Oda to tie-in to Ula via the existing Oselvar tie-back development. The Oda gas volumes will be re-injected into the Ula reservoir as part of the existing Water Alternative Gas injection scheme resulting in an increase in Ula production.

In addition to these developments there are a number of other brownfield projects under evaluation including Tambar Artificial Lift, Tambar Infill Drilling and Valhall North Flank Water Injection. Evaluation of the Hod Field Development is also expected to be initiated in 2017.

Discoveries

The most recent discovery the BP Norway portfolio was Snadd Outer also known as Snadd North. This was a BP operated well.

Exploration Activity

In the Awards in Pre-defined Areas ("**APA**") 2015 (APA 2015) licensing round BP Norway was awarded one operatorship and 23.8% share in the production license PL 839, block no: 6507/1,2,4,5. The PL 839 is additional acreage near to the Skarv Unit adding to an extensive prospect inventory in the area. It is anticipated that successful discovery(s) could result in a new tie-back to Skarv which together with development of other Skarv prospects could significantly prolong the life of the Skarv FPSO development. The terms of the license require that a decision to drill be made by February 2018.

5.4 Licence Portfolio, Reserves and Resources

Licenses

BP Norway's license portfolio is included in table below:

License	Field/prospect	Interest	Operator	Expiry	Phase
006 B	Valhall	35.833333%	BP Norge AS	31.12.2028	Production
019	Ula	80%	BP Norge AS	01.01.2029	Production ext.
033	Hod	37.5%	BP Norge AS	31.12.2021	Production ext.
033 B	Valhall	37.5%	BP Norge AS	31.12.2028	Production
065	Tambar	55%	BP Norge AS	01.01.2022	Production ext.
212	Skarv	30%	BP Norge AS	02.02.2033	Production

212 B	Skarv	30%	BP Norge AS	02.02.2033	Production
212 E	Skarv	30%	BP Norge AS	02.02.2033	Production
261	Skarv	50%	BP Norge AS	12.05.2036	Production
262	Skarv	30%	BP Norge AS	02.02.2033	Production
300	Tambar Øst	55%	BP Norge AS	12.12.2023	Production
712	TFO2013	20%	Eni Norge AS	21.06.2018	Initial
839	TFO2015	23.835%	BP Norge AS	05.02.2020	Initial

PL 712 is in the process of being relinquished to the Norwegian state.

5.5 Non-operational Material Contracts

Except for the Transaction and the contract described below, BP Norge has not entered into any material contracts outside the ordinary course of business for the two years immediately preceding the date of this Information Memorandum, and BP Norge has not entered into any contracts containing obligations or entitlements that are, or may be, material to the issuer as of the date of this Information Memorandum.

On 31 August 2015, BP Norge, Gassco AS and BP Corporation North America Inc. ("**BPCNAI**") entered into the Second Guarantee Amendment to the Guarantee of 25 April 2005 (the "**Gassco Guarantee**"). Pursuant to the Gassco Guarantee, BPCNAI had agreed to guarantee the obligations of BP Norge to make payments to Gassco AS under the Terms and Conditions for Transportation of gas in Gassled, up to a maximum aggregate amount of NOK 188,636,000. The guarantee amount under the Gassco Guarantee was later increased to NOK 800,000,000, and pursuant to the Second Amendment to the Gassco Guarantee, BP Norge, Gassco AS and BPCNAI agreed that the guarantee amount should be increased from NOK 800,000,000 to NOK 900,000,000. On this basis, BP Norge and BPCNAI have also on 31 August 2015 entered into the First Amendment to the Agreement relating to the Gassco Guarantee, dated February 2011. The amendment sets out that the amount of the annual fee payable by BP Norge to BPCNAI as consideration for BPCNAI guaranteeing the payment obligations of BP Norge under the Gassco Guarantee was increased from 11.78 basis points to 48 basis points of the amount guaranteed.

BP Norge has in the last two years entered into various procurement and supply contracts, as well as supplements and amendments to such contracts entered into prior to this period, in relation to the Production Licence interests owned by BP Norge.

5.6 Significant Recent Trends

Year to date production has averaged 57 mboed vs. 62 mboed for 2015 full year. The decrease is due to major planned turnarounds on the southern fields, Ula and Valhall. The Ula and Valhall fields came back on production at the end of June. Skarv will also have a planned shut-down around end of August until mid-September.

Year to date cash costs have averaged USD 17.7 boe vs. USD 21.2 boe for 2015 full year. The decrease is primarily as a result of the businesses simplification and efficiency (S&E) benefits being delivered.

Year to date decommissioning costs are USD 50 million vs. USD 99 million for 2015 full year. The Maersk Reacher rig has performed plugging abandonment of old wells at Valhall.

Year to date capital expenditure is USD 7 million vs. USD 77 million for 2015 full year. During 2016 a platform rig re-certification programme has been ongoing at Valhall.

Overall BP Norge's portfolio continues to generate significant positive cash flow despite current hydrocarbon price environment.

5.7 Recent Developments

Other than as set out below, there has been no significant change in BP Norge's financial and trading position since the first half of 2015:

- 19 January 2016: BP Norge was awarded one exploration license (PL 839, block 6507/1, 2, 4, 5) in the Awards in Pre-defined Areas 2015 (APA 2015) licensing round.

- 27 January 2016: BP Norge announced plans to reduce staffing by around 210 people over the next two years.

- 26 April 2016: The the Petroleum Safety Authority ("**PSA**") approved the use of the Ula export pipeline until the current Ula license expiry in 2028.

- 9 June 2016: BP Norge confirmed that the staff reduction in the onshore organization has been concluded in line with overall plans. The plans for offshore staff reductions will continue in line with previous announcement for a 2017 implementation.

- 10 June 2016: BP Norge and the Company announced the creation of Aker BP ASA, an independent oil and gas company combining the assets and expertise from both companies' Norwegian exploration and production operations to form the largest Norwegian independent oil and gas producer.

- 22 June 2016: The PSA approved the use of the wellhead platform (WP) on the Valhall field center until the current license expiry in 2028.

- 24 June 2016: BP Norge approved to progress the Snadd project within the Skarv field into the optimise phase.

- 8 July 2016: The PSA approved the use the facility on the Tambar field until the current license expiry in 2022.

5.8 Legal and Arbitration Proceedings

Except for the proceedings described below, BP Norge has not been involved in any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened), during the last twelve months which may have, or have had in the recent past, significant effect on the financial position or profitability of BP Norge.

In December 2015, an arbitration tribunal found in favour of BP Norge in respect of a dispute between the Ula owners and Blane owners as to whether specific intervention work on the Blane Riser should be remunerated through the fixed tariff.

6. THE COMPANY FOLLOWING COMPLETION OF THE TRANSACTION

This Section provides information about the prospects of the results of the Transaction and its expected implications on the Company following the Transaction and should be read in conjunction with other parts of the Information Memorandum, in particular Section 5 "Presentation of BP Norge" and Section 9 "Unaudited Pro Forma Financial Information". The following discussion contains Forward-looking Statements that reflect the Company's plans and estimates. Factors that could cause or contribute to differences to these Forward-looking Statements include, but are not limited to, those discussed in Section 1 "Risk Factors" and the "Cautionary Note Regarding Forward-Looking Statements" on page 1.

6.1 The Company Following Completion of the Transaction

Following completion of the Transaction, Aker BP will hold a portfolio of 104 licenses on the NCS, of which 56 are operated. The total net proved plus probable reserves (P50/2P) for the combined company are estimated at 795 million boe, with a 2015 joint production of approximately 122,000 barrels of oil equivalent per day, reference is made to 2015 Annual Report for the Company and Appendix B—Expert Opinion.

Aker BP will from completion be the operator of 9 producing fields including Alvheim, Bøyla, Volund, Vilje, Ula, Tambar, Valhall, Hod, and Skarv. First oil from Ivar Aasen is planned for December 2016, which leads to 10 operatorships in producing fields.

Aker BP will have a balanced portfolio of operated assets and a high quality inventory of non-sanctioned projects and discoveries, with potential to reach production above 250,000 barrels of oil equivalent per day in 2023.

6.2 Strengths and Strategies Following Completion of the Transaction

Aker BP has the ambition to leverage on the Company's lean and nimble business model and will gain access to technological know-how and capabilities, through the industrial collaboration with BP.

Maintaining the Company's cooperative culture with will be a key goal for Aker BP. Another key element will be to maintain the good mixture of younger talents and experienced people, together with the ability to make fast decisions. Aker BP will have visible leaders that are hands-on and operationally involved to create a flat structure with a high degree of openness, cooperation and informality.

Aker BP will be a full-fledged oil company with activities within exploration, development and production. Aker BP will have a resource base and organisation as a sizeable player. The development of the Ivar Aasen and the Johan Sverdrup field will further grow Aker BP's production volumes. Aker BP will become the largest independent oil & gas company on the NCS in terms of activity and production.

Exploration will continue to be a core activity for the combined company. In addition to organic growth, Aker BP will also continuously assesses potential acquisitions on the NCS which offer access to high quality assets and potential upside that is in line with the Aker BPs strategies. If deemed beneficial to achieve the Aker BPs overall strategies and objectives, the Company may also from time to time reduce its ownership interest in certain licenses or enter into farm-down arrangements

Through Aker ASA's 40 % and BP plc.'s 30 % indirect ownership in the combined company, Aker BP is backed by long term industrial owners with a strong balance sheet, and a strategy of supporting Aker BP with their capital requirements for development and growth.

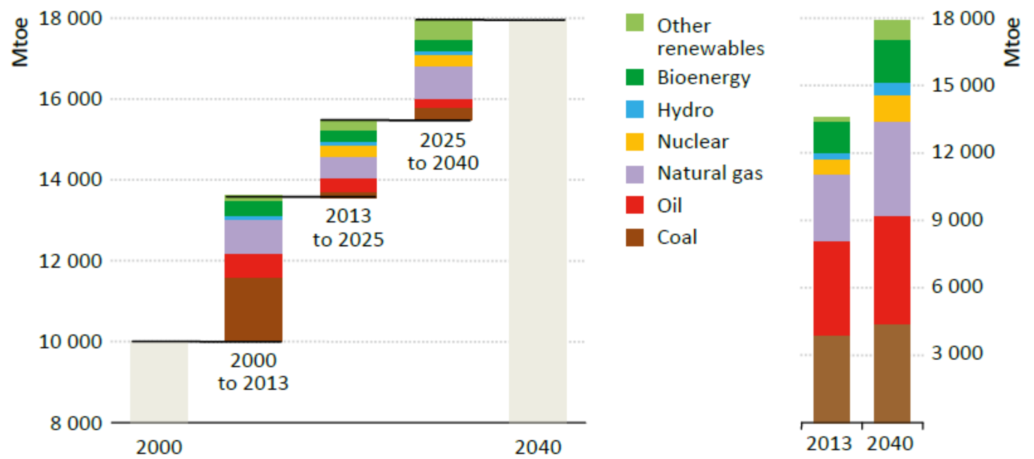
7. INDUSTRY OVERVIEW

This Section discusses the industry and markets in which the Company operates. Certain of the information in this Section relating to market environment, market developments, growth rates, market trends, industry trends, competition and similar information are estimates based on data compiled by professional organisations, consultants and analysts in addition to market data from other external and publicly available sources, and the Company's knowledge of the markets. There are different views related to market developments reflecting the overall uncertainties. Any forecast information and other Forward-looking Statements in this Section are not guarantees of future outcomes and these future outcomes could differ materially from current expectations. Numerous factors could cause or contribute to such differences, see Section 1 "Risk Factors" for further details.

7.1 Energy Overview

The dynamics in the energy markets are determined more and more by the emerging economies. Since 2014 non-OECD countries have used more oil than OECD countries and the gap will widen in the years to come. The International Energy Agency's ("**IEA**") "Global Energy Outlook 2015" (GEO 2015) predicts an increase of one third in world energy use towards 2040. Following the COP21 agreement, a move towards lower carbon and more energy efficiency is expected. The report predicts that fossil fuels will remain the dominant source of energy in 2040, even though consumption of non-fossil fuel is expected to increase to 25% from 19%. In the New Policies Scenario (the central scenario in GEO 2015 based on pledges in the run-up to COP21), demand for all fossil fuels increases in the period. Oil demand is predicted to increase by 15%, with growth slowing gradually over time, from an average of 0.85 million boe/year in 2020 to 0.40 million boe/day thereafter. Oil demand is expected to become more concentrated in the transport and petrochemicals sector, and backed out of power generation and buildings. The Global market for natural gas is expected to increase by 47% to 2040, with power generation as the main driver for demand growth.

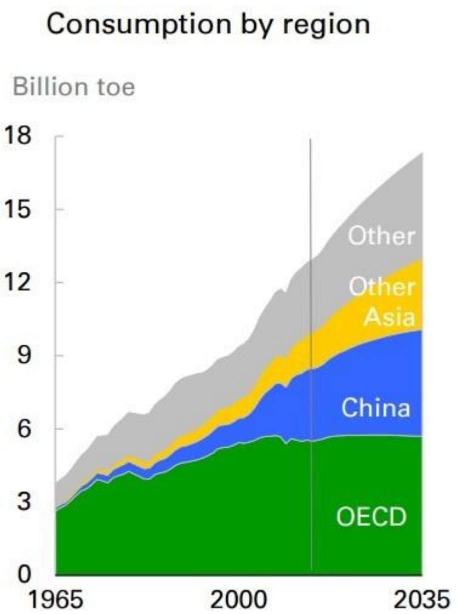
Below is a prediction of world energy demand by fuel from GEO 2015. Source: IEA "Global Energy Outlook 2015"

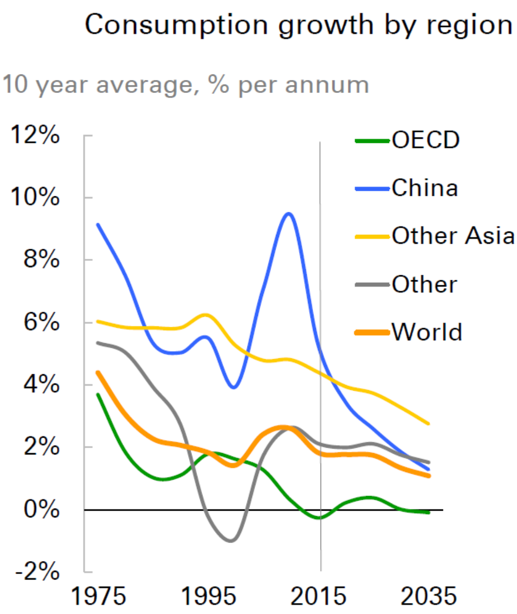


7.2 Energy Demand

Primary energy consumption is in BP's "Energy Outlook 2035" report (2016 Edition) projected to increase by 34% between 2014 and 2035, averaging at 1.4% per annum. This is less rapidly than the global economy, reflecting significant faster falls in energy intensity (energy used per unit of GDP). China and India are accounting for more than half of the world's growth in energy demand towards 2035. Fossil fuels will remain the dominant source of energy, providing around 60% of the growth and almost 80% of total energy supply in 2035. Medium-Term Oil Market Report 2016 predicts a forecasted average annual growth in oil demand at 1.2% towards 2021. The demand growth is constrained by improved vehicle fuel efficiency and structural changes to the Chinese economy.

Below is an overview of world energy consumption by region.





Source: BP Energy Outlook to 2035, January 2016

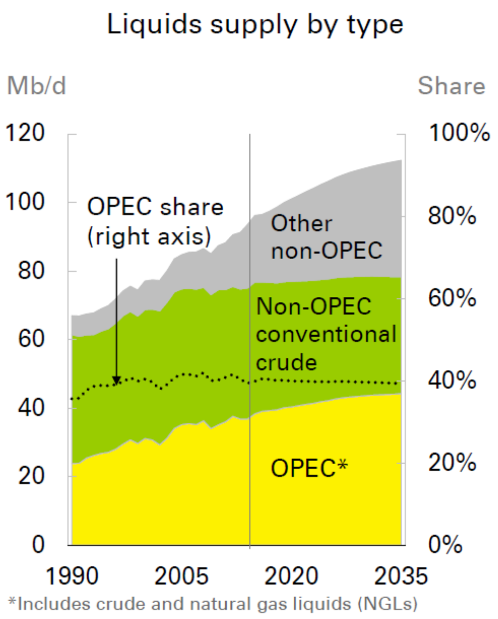
The GEO 2015 predicts a shift in the weight of world energy demand towards emerging economies, and the non-OECD markets will drive all growth in energy demand. The OECD energy demand is expected to peak in 2020, at levels a little higher than today, and then fall with 3% towards 2040.

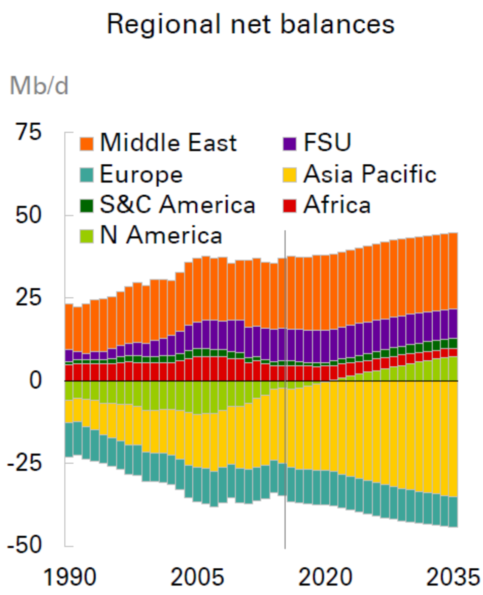
7.3 Energy Supply

IEA's Medium-Term Oil Market Report 2016 predicts that global oil supply will slow down over the period 2015-2021, as lower oil prices are eroding the world's supply capacity. Cuts in global exploration and production spending are predicted to be 17% in 2016, following a reduction of 24% in 2015. Following an expected decline of 0.6 million boepd in 2016, the non-OPEC supply will be steady in 2017 and increase from 2018 to a predicted production of 57.9 million boepd in 2021, up 2.0 million boepd compared to 2015. The increase is expected to mainly come from the Americas. Low oil prices force the OPEC producers to re-consider development projects and OPEC production is only rising by 0.8 million boepd by 2012.

In 2014 and 2015 supply exceeded demand by 0.9 million boepd and 2.0 million boepd respectively, leading to low oil prices. IEA's Medium-Term Oil Market Report 2016 estimates that oil supply and demand will be aligned in 2017, but predicts that the stocks accumulated throughout this period will act as a damper on the oil price recovery. BP's Energy outlook 2035 supports the view that non-OPEC is the largest source of supply growth.

Below is an overview of liquids supply by type and regional net balance.



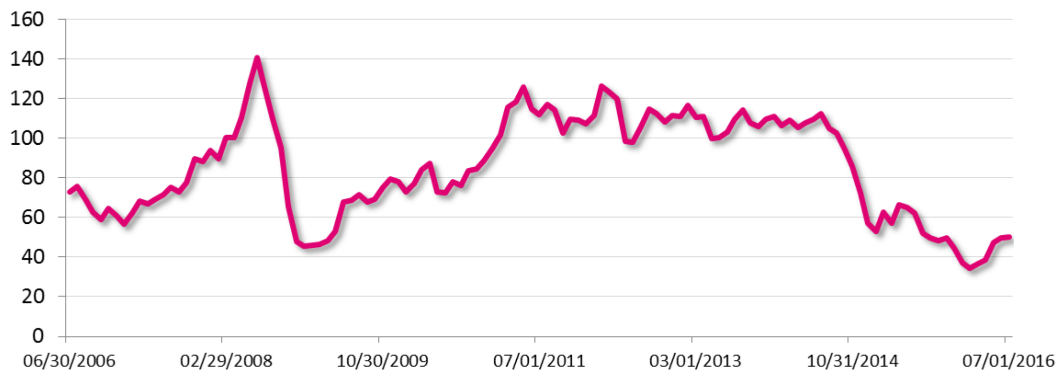


Source: BP Energy Outlook to 2035, January 2016

7.4 Oil Price

As of June 10, 2016 the Brent crude oil price was USD 50.4 per barrel, following a recovery from being down to USD 27.7 per barrel in January 2016. All time high came back in July 2008 with a price at USD 146.1 per barrel. Following strong growth in oil supply and weak demand growth the oil prices fall sharply late 2014/early 2015 and have remained low since. Currently, the market is oversupplied by oil, and it is difficult to predict when the market will be back in balance.

The figure below illustrates Brent crude oil price for the last ten years.



Source: Factset

The oil price is affected by a number of factors, including, but not limited to, changes in supply and demand, OPEC regulations, weather conditions, regulations from domestic and foreign authorities, political and economic conditions and the price of substitutes.

It should be noted that the oil market is dynamic and that the demand for oil to some extent is inversely linked to the price. Longer periods of high oil prices can therefore lead to increased use of alternative energy sources at the cost of oil demand.

Twice a year, or more frequently if required, the Oil and Energy Ministers of the OPEC countries meet to decide on the organisation's output level and consider whether any action to adjust output is necessary in the light of recent and anticipated oil market developments. Over the last two years, the members of OPEC has seemed determined to maintain and expand their markets share, which has resulted in the first free oil market since the pioneer years. Every oil producer, including OPEC, sells their entire production for whatever price they can achieve in the market. The long-term consequences of the new market dynamics are still not fully understood.

7.5 E&P Spending

IEA's Medium-Term Oil Market Report 2016, predicts decline in E&P spending for the second consecutive year in 2016. Following a 24% spending cut in 2015, the report estimates further 17% reduction in spending for 2016. The spending cuts will be partly offset by cost cut in the industry. The expected spending in 2016 is estimated to be USD 330 billion, and as companies are re-evaluating investment programs and budgets, further cuts can not be ruled out. The biggest reduction in investment is expected to materialise in the United States and Canada. In Europe both United Kingdom and Norway had large investment cut last year, and spending is expected to come further down.

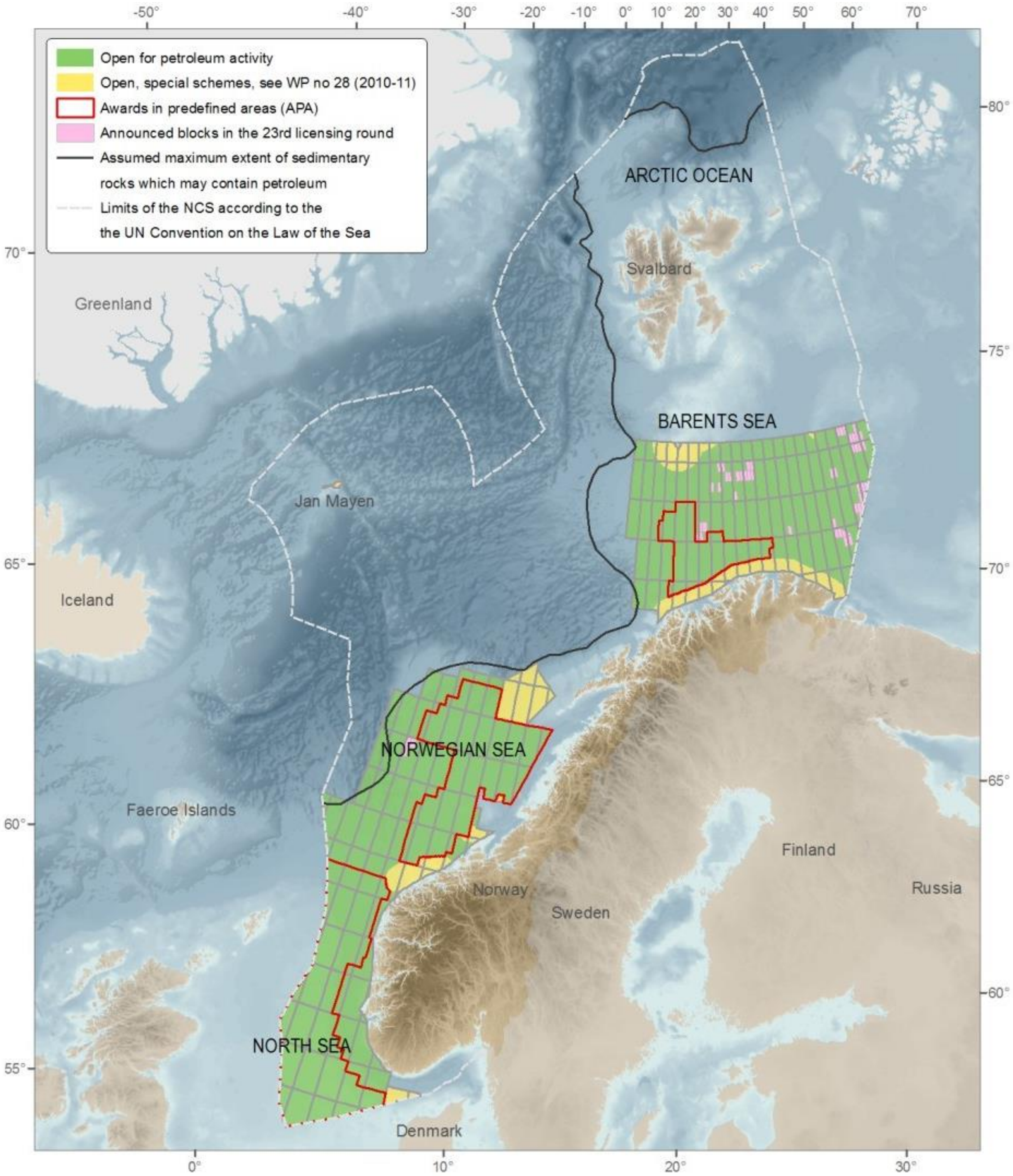
7.6 The Norwegian Continental Shelf

The NCS is the continental shelf over which Norway exercises sovereign rights as defined by the United Nations Convention on the Law of the Sea and the Norwegian Petroleum Act. Its major parts are the shelves of the North Sea, Norwegian Sea and Barents Sea.

The area of the shelf is four times the area of Norway mainland and constitutes about one-third of the Europe continental shelf, and in 2015, Norway was the world's third largest gas exporter and the 8th largest oil exporter.

Today, the petroleum industry is the largest industry in Norway measured in value creation, state revenues and export value. Since production started, the industry has contributed approximately USD 1,410 billion, or NOK 12,000 billion, to the Norwegian GDP measured in year 2015 value. The industry has therefore been a cornerstone for building the Norwegian welfare state and the Norwegian economy in general. The Norwegian State has decided that all petroleum operations must benefit society as a whole to the greatest extent possible. This is the primary reason of why the State claims a large share of the value creation through taxes, fees and the State's Direct Financial Interest (SDFI). These revenues are currently being invested in the Government Pension Fund Global, which at the end of 2015 was valued at approximately USD 890 billion.

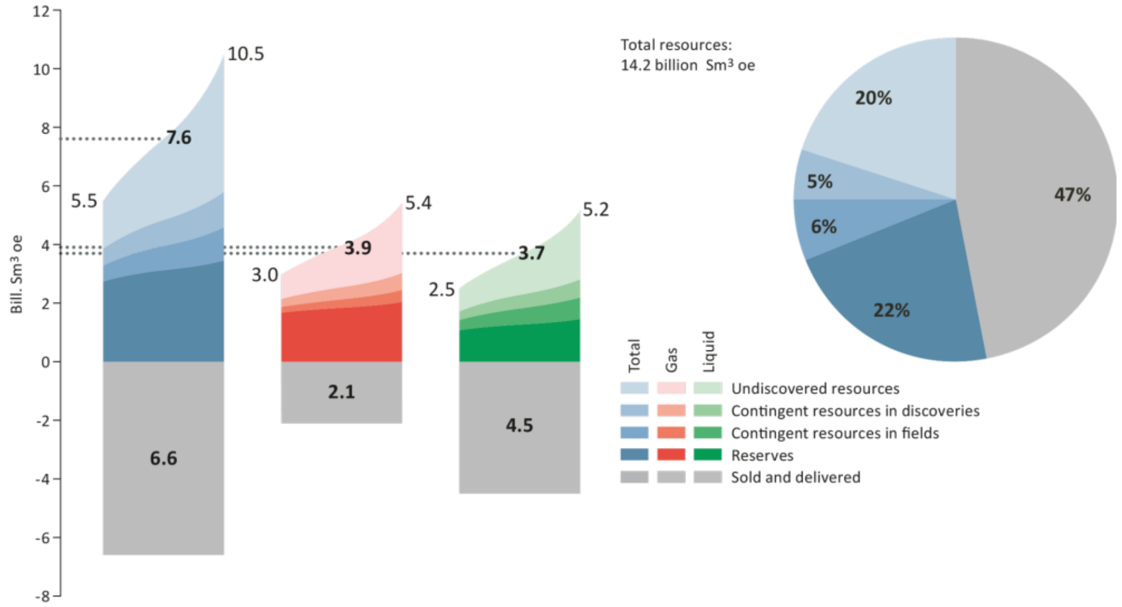
Below is an overview of the status of the different areas on the NCS.



Source: Norwegian Petroleum Directorate (NPD), www.npd.no

7.7 Production on the NCS

The discovery and subsequent development of Ekofisk in 1969 marked the beginning of oil exploration and production on the NCS. Although most of the NCS has reached its mature phase, there are still large reserves in the province remaining to be found or produced. As of year-end 2015, the Norwegian Petroleum Directorate ("NPD") estimates in its annual resource accounts, that the total recoverable resources on the NCS are approximately 89.3 billion boe. Out of this, approximately 42.0 billion boe is produced. This is illustrated in the figure below, which shows the distribution of petroleum resources by maturity as of 31 December 2015 on the NCS.



Source: Norwegian Petroleum Directorate (NPD), www.npd.no

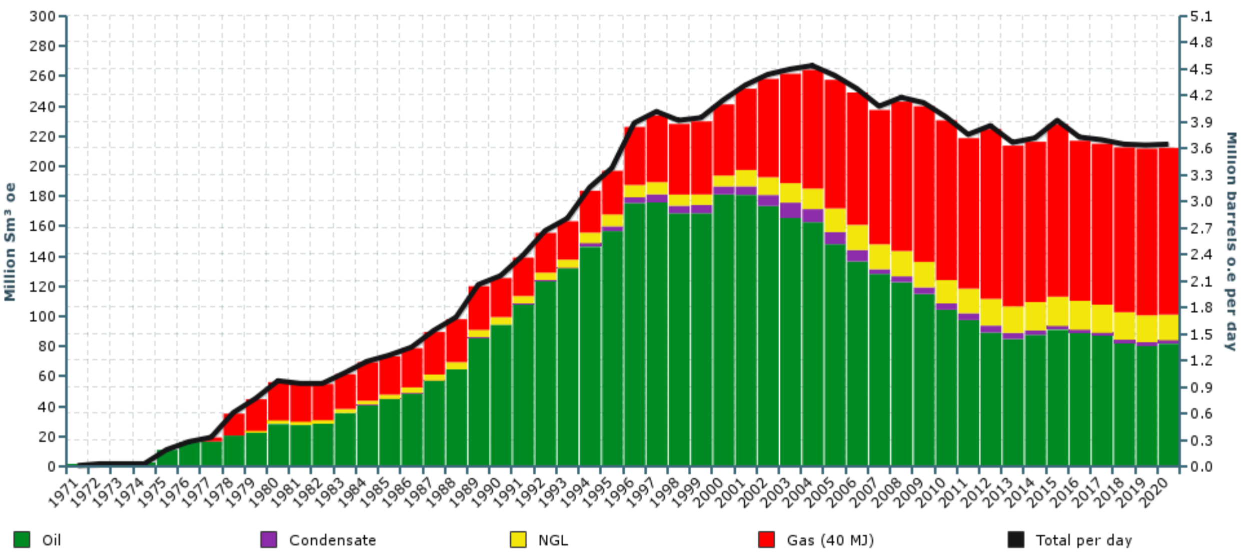
The oil production from existing fields on the NCS has peaked and is declining. Oil production in 2015 was 91.0 million Sm3 (1.6 million bbls per day), compared with 87.7 million Sm3 (1.5 billion bbls per day) in the previous year. 82 fields contributed to the total oil production in 2015.

Continued investments in the drilling of new development wells and other measures to improve recovery are important for the oil production on the NCS.

In 2015, 114.9 billion Sm3 gas was sold. This was new record, an increase of 8.1 billion Sm3 compared with 2014 (7.5 per cent). The NPD expects gas output from existing fields to increase somewhat during the next five years.

In 2015, 19.6 million Sm3 (0.3 million boepd) NGL and 2.5 million Sm3 (0.04 million boepd) condensate was produced on the NCS.

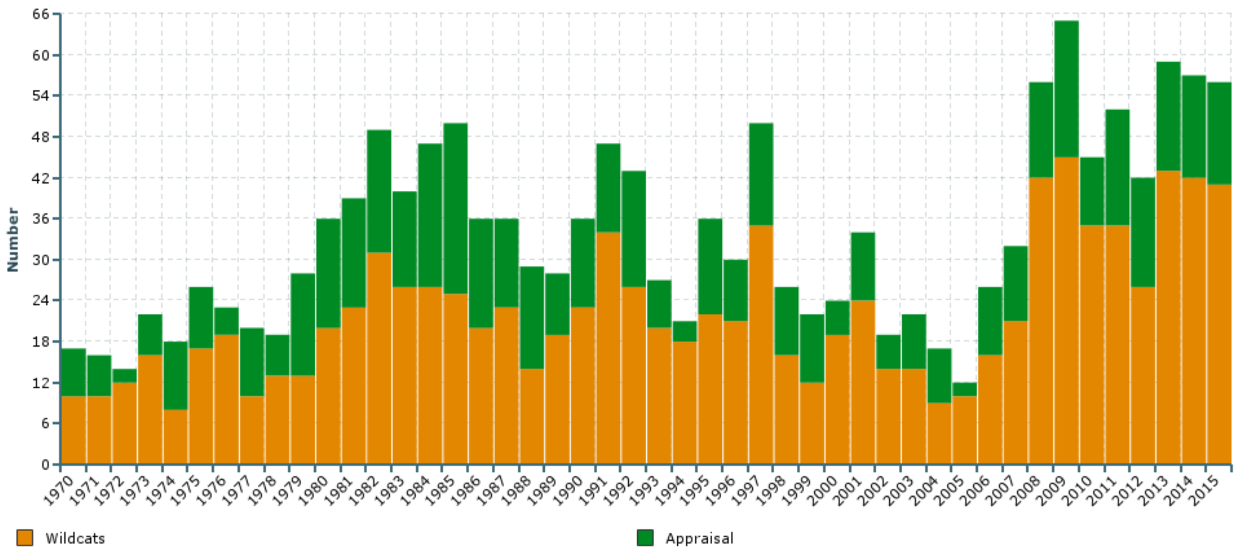
Below is an overview of the production development from 1971 and forecast to 2020, where 1 Sm^3 = 6.29 barrels.



Source: Norwegian Petroleum Directorate (NPD), www.npd.no

In order to increase the production and tap the resource potential on the NCS, the oil industry has to increase its exploration efforts. The number of wildcats (oil wells in an unexplored area) and appraisal wells being drilled on the NCS were historically low until 2005, but started to increase thereafter, due to the Norwegian government's ambition to increase drilling on the NCS. The number of spudded exploration wells reached a record high of 65 wells in 2009. Following the drop in commodity prices during the second half of 2014, the industry has reduced spending on exploration activities. In 2015, 41 wildcats and 15 appraisal wells were commenced. The development in exploration activity is illustrated in the figure below.

The figure below shows the number of wildcat wells and appraisal wells 1970 – 2015.



Source: Norwegian Petroleum Directorate (NPD), www.npd.no

7.8 Measures for increasing production on the NCS

Production from existing oil fields on the NCS is declining, and a step-up in exploration activity combined with increased production from existing fields, is needed to reach government stated production goals. Among the measures taken to stimulate increased exploration are (i) a more flexible and effective exploration policy (i.e. increasing acreage available for exploration and increasing the number of licenses awarded), (ii) increasing the number of companies on the NCS, and (iii) tax incentives to encourage companies to increase the exploration activity. These measures are briefly described in the following sections.

Increased acreage

A first measure taken by the government to increase the activity on the NCS was to increase the acreage available for exploration, both in mature and immature areas. To increase the activity in mature areas the Norwegian government started to award new production licenses annually in 2003, the APA. Since the first APA round in 2003, the APA acreage has been expanded several times. In the APA 2015 the government awarded 56 licenses, while the numbers were 54, 65, 51, 60, 49, 38, 35 and 52 in APA14, APA13, APA12, APA11, APA10, APA09, APA08 and APA07, respectively.

In 2015, the government for the first time since 2004 opened up new acreage announcing the 23rd licencing round. The 23rd licensing round opened up 34 blocks in the formerly disputed area towards Russia in the south-eastern Barents Sea, 20 blocks in other parts of the Barents Sea and three blocks in the Norwegian Sea. In 2016, the government awarded ten new licenses consisting of 40 blocks in total in this area.

Increased number of companies on the NCS

In addition to increasing the acreage available for exploration, the Norwegian government also expressed its desire to increase the number of companies on the NCS. The Norwegian government acknowledged that the interest among many of the established players for mature areas on the NCS is moderate, and have stressed the importance of new and creative solutions to increase the production on the NCS. The criteria for award of licenses in APAs and Licensing Rounds are factors like technical quality of the application, demonstrated quality of the company and the proposed work program. There is no upfront payment for the production licenses, however, a fee of NOK 123,000 applies for the handling of the license application, which is awarded by the MPE based on a full technical evaluation by the NPD. The MPE is required to make its decision on the basis of objective, non-discriminatory and published criteria. The authorities have a strong focus on attracting technically competent companies that can contribute to the development of the NCS and have therefore introduced a prequalification system. All new oil companies have to be prequalified by the authorities before they can be awarded or acquire interests in production licenses. This system ensures that only companies with proper and relevant competence and system in place, as well as necessary financial resources, are approved as licensees on the NCS. According to NPD at the end of 2015, 34 companies were operators on the NCS and a further 20 are partners in production licenses.

Tax incentives

Companies not in a tax paying position may annually claim a refund from the State of the tax value of direct and indirect cost, except financial charges, incurred in exploration for petroleum resources. The tax value is set to the total of direct and indirect costs multiplied by the tax rate, currently 78 per cent. The refund will reduce the tax loss carry forward correspondingly. The amount of exploration cost may not exceed the annual net loss from the petroleum activities of the taxpayer, to ensure that the costs are not already set off against taxable income.

7.9 Unopened areas

There are still large areas of the NCS that the Norwegian Parliament has not yet opened for petroleum activities. This applies to the area surrounding Bjørnøya in the Barents Sea, the north-eastern Norwegian Sea, Skagerrak and the areas surrounding Jan Mayen. The general rule for unopened areas is that the Norwegian Parliament must resolve to open an area for petroleum activities before a licensing round can be announced. The basis for such decisions must include preparation of an impact assessment to consider factors such as economic and social effects, as well as environmental effects the activities could have for other industries and the surrounding district.

7.10 Regulatory Framework on the Norwegian Continental Shelf

Regulatory Overview

The main regulatory authorities governing the petroleum industry on the NCS are the Norwegian Parliament, the MPE, the Norwegian Petroleum Directorate ("**NPD**"), the PSA, the Ministry of Labour ("**MoL**"), the MoF, the Oil Taxation Office ("**OTO**") and the Norwegian Environmental Agency ("**NEA**").

The ultimate regulatory authority rests with Stortinget. The MPE is responsible for ensuring that the petroleum activities are carried out in accordance with the regulatory framework laid down by Stortinget. Subordinated to the MPE is the NPD whose activities relate to resource management and day-to-day issues. The PSA regulates the technical and operational safety of the operations and the MoL regulates the working environment. The MoF is responsible for the policies and legislation regarding the taxation in the petroleum industry whilst the OTO conducts the annual tax assessments. Finally, NEA has regulatory responsibility for pollution caused by petroleum activities on the NCS.

The Petroleum Act provides the legal framework for the proprietary rights to subsea deposits as well as the licensing system. Section 1-1 of the Petroleum Act states that the proprietary rights to subsea petroleum deposits is vested in the Norwegian State. It also governs the award of production licenses as well as governing the exploration, development, production and transportation of petroleum on the NCS.

The Norwegian State is the largest participant on the NCS, with their shareholding in in Statoil Petroleum AS and through the State's direct participation in various exploration and production licenses through the Direct Financial Interest, managed by Petoro AS, a State-owned company.

The 1975 Act Relating the Taxation of Subsea Petroleum Deposits provides the legal basis for the taxation of petroleum activities on the NCS.

Licensing System

There are two systems for awarding production licenses on the NCS: (i) the ordinary numbered concession rounds; and (ii) the APA.

The ordinary numbered concession rounds are normally held every two years and these cover new acreage on the NCS. In 2003 the State introduced an APA award system where mature areas on the NCS, normally close to existing or planned infrastructure, are released for applicants. In order to be eligible to apply in either the numbered concession rounds or the APA rounds a company that is not already an established license holder on the NCS needs to pre-qualify as a potential licensee on the NCS. This pre-qualification process means that a company must meet certain criteria regarding their organisation, qualifications of staff and their financial strength among other things. An additional and more rigorous pre-qualification process is required of any company which is not already an operator which wants to become an operator on the NCS. Companies can apply for production licenses either on their own or as part of a group where one company applies as the operator and the rest as licensees. The application must be submitted within a set deadline along with an application fee of NOK 123.000 (application fee for the APA 2016 application) for the cost of handling the applications.

The MPE assesses the applications and will have the ultimate saying in which companies, or groups of companies, are awarded which licenses. One of the most important factors for the MPEs assessment of the applications is the extent to which a given company, or a group of companies, is willing to commit to firm a work program. Where a group of companies is awarded a license, the MPE will appoint one of the companies as the operator of the license, i.e. the company responsible for the joint activities of the license group.

The MPE will often require a parent company guarantee, in a form specified by the MPE, from the parent companies of applicants for the fulfilment of the obligations set out in the license as well as the potential liability towards the State. The license group must be in a position to cover the capital expenditure costs of the work obligations set out in the production license.

Terms of the Production Licenses

A production license is awarded for an initial period of up to ten (10) years and sets out work obligations, which must be completed within this initial period. When such work obligations have been fulfilled, the licensees have the option to apply for the term of the license to be extended for a period of up to thirty (30) years, however the area covered by the license will at this point be reduced. The MPE has recently, in mature acreage on the NCS, required that license groups make a drill or drop decision for whether to drill an exploration well and retain the license or to drop the license within a relatively short time-frame (e.g. two (2) years). Once a production license enters into the extended period, an area fee will become applicable. The area fee is set by the NPD and is calculated on a square kilometre basis with increasing area fees applying for the first, second and any subsequent years. The current area fee rates are NOK 34.000 per km^2 for the first year, NOK 68.000 per km^2 for the second year and NOK 137.000 per km^2 for each subsequent year

License Agreements

Licensees must enter into an agreement for the petroleum activities as a condition of being awarded a license. Such agreements regulate the voting rights within the license group as well as appending the joint operating agreement ("**JOA**") and the accounting agreement, both of which are standard form agreements on the NCS. The JOA regulates the relationship between the licensees. It forms the basis for the operation of the activities in the license, including setting out the operators' duties, the mechanism for allocation of costs and the decision-making processes within the license group. The license group must establish a management committee representing all licensees, which acts as the highest ranked decision-making body in the joint venture. All petroleum produced in a license is allocated to each licensee, and the operator, in accordance with their participating interest share in the license.

Where petroleum deposit(s) stretch over two or more licenses, the relevant licenses will need to enter into a unitisation agreement which regulated the licensees' rights to the petroleum deposit(s). Such unitisation agreement in effect replaces the underlying JOA and accounting agreements for the licenses with respect to the subject deposit(s) that stretches over more than one production licenses. The unitisation agreement will determine how much of the total petroleum deposit will be allocated to each license. An initial distribution may be subject to a redetermination at a later stage.

Where licensees wish to transfer part or all of their participating interest in a license, such a transfer is subject to MPE approval and a tax clearance from the MoF, although the principle of tax neutrality is often applied meaning that any gain by the seller is not taxable and any cost for the purchaser is not tax deductible. A transfer of a controlling interest in a company, which holds participating interests in production licenses are also subject to MPE approval.

Exploration

Operators on the NCS have an obligation to obtain permits from the PSA and the NPD in advance of commencing any drilling operations. Drilling exploration wells (to and in oil-bearing strata) are permitted solely pursuant to production licenses, not exploration licenses. A separate consent from the PSA and NPD is required for each exploration well. The operator must submit detailed information with regard to both the technical and environmental aspects of the planned operation when submitting such an application. Comprehensive HSE procedures must also be in place, including the establishment of emergency preparedness procedures. The operator will also need to obtain permits to discharge to sea and air from the Norwegian Pollution Control Authority and this is a part of the consent to drill.

Development

In order to develop a petroleum deposit, the operator must prepare a PDO which needs to be approved by the MPE. A PDO must set out the development solution, estimated development costs, production profile for the deposit as well as information regarding decommissioning. It will also need to include information on facilities for utilisation and transportation of petroleum.

The JOA states that the management committee in the license joint venture must decide on whether to submit a PDO to the MPE for approval. Where the estimated investment is more than NOK 10 billion the PDO will also be presented to Stortinget. Each licensee must individually accede to the PDO by giving notice of such to the MPE. If a licensee does not accede to a PDO, the licensees that have acceded the plan may carry out the project on their own ("sole risk"). The licensee not acceding to the PDO will retain its rights in the license acreage outside the deposit, which is subject to the PDO.

Infrastructure

In order to construct and operate facilities for the transportation and utilisation of petroleum (e.g. pipelines and processing facilities) a Plan for Installation and Operation ("**PIO**") must be submitted to the MPE for approval, where such facilities are not already included in an approved PDO.

MPE often decides that owners of transportation and processing facilities must allow third parties to have access to such facilities. The MPE can impose a solution on parties who are unable to agree on shared use of such facilities.

Gassled, the joint venture established on 1 January 2003 is the formal owner of the Norwegian gas transportation infrastructure as well as the receiving terminals in the UK and on the European continent. These facilities are subject to a general principle of third party access.

Production

The NPD issues annual production permits based on the PDO taking into consideration proper resource management ensuring the maximum depletion of petroleum from the reservoirs. These permits allow the operator to produce defined volumes of petroleum on behalf of their license groups. As mentioned above, the license groups also require consent to use facilities and installations as well as permits for discharges and emissions to sea and air.

Environmental conditions for exploring and development

Liability for pollution damage. Chapter 7 of the Petroleum Act stipulates a strict liability for pollution damage on all the licensees. In other words, a licensee is liable for pollution damage without regard to fault. However, if it is demonstrated that an inevitable event of nature, act of war, exercise of public authority or a similar force majeure event has contributed to a considerable degree to the damage or its extent under circumstances which are beyond the control of the liable party, the liability may be reduced to the extent it is reasonable, with particular consideration to the scope of the activity, the situation of the party that has sustained damage and the opportunity for taking out insurance on both sides.

A claim against the license holders for compensation relating to pollution damage shall initially be directed to the operator. If any part of the compensation is left unpaid on the due date by the operator, this part shall be covered by the licensees in accordance with their participating interest in the license. If any of the licensees fails to cover their share, the liability relating to this share shall be allocated proportionately between the others licensees.

Discharge permits. Emissions and discharges from Norwegian petroleum activities are regulated by several acts, including the Petroleum Act, the CO2 Tax Act, the Sales Tax Act, the Greenhouse Gas Emission Trading Act and the Pollution Control Act. Discharge of oil and chemicals in relation to exploration, development and production of oil and natural gas are regulated under the Pollution Control Act (the "Pollution Act"). In accordance with the provisions of the Pollution Act, the operator must apply for a discharge permit from relevant authorities on behalf of the license group in order to discharge any pollutants into the sea. Further, the Petroleum Act states that burning gas in flares beyond what is necessary to ensure normal operations is not permitted without approval from the MPE.

All operators on the NSC have an obligation to establish sufficient procedures for the monitoring and reporting of any discharge into the sea. The Climate and Pollution Agency, the Norwegian Petroleum Directorate and the Norwegian Oil Industry Association have established a joint database for reporting emissions to air and discharges to sea from the petroleum activities, «Environmental Web» (EW). All operators on the NCS report emission and discharge data directly into the database.

Decommissioning

The licensees are required to submit to the MPE a plan for decommissioning and cessation of the petroleum activities. The MPE then decides, based on the plan, on the disposal of the facilities. The decommissioning costs are carried by the licensees, and are petroleum tax deductible for current licensees. Following transfer, cf. below, of a license share, a company will remain liable on a secondary pro rata basis for decommissioning cost if its successor defaults on its obligations to pay such cost. Such secondary liability is on after tax terms, meaning that the company being held liable on a secondary pro rata basis will not get a tax deduction.

The Petroleum Tax Act

For companies participating in production and transportation of petroleum products on the NCS, there are two, partially overlapping income tax regimes: ordinary income tax imposed by the general rules in the Norwegian General Tax Act of 1999 (the "**GTA**") and the special petroleum tax on income imposed by the Petroleum Tax Act (the "**PTA**"). As a result, the total marginal income tax rate for companies engaged in E&P activities on the NCS is 78 per cent, consisting of a 25 per cent general income tax and a 53 per cent special petroleum tax to the State levied on income generated by exploitation, treatment or transportation of petroleum, ref. the PTA section 5. The petroleum tax applies on a corporation net profit level, not on a ring-fenced basis. Losses generated by other activities may as a general rule not be set off against assessed income for special tax (53 per cent) purposes and there are limitations on the right to set of other losses against the general tax (25 per cent) basis.

Taxable income is computed according to the general tax legislation and particular rules set out in the PTA. Gross income generated by oil sales is assessed according to a norm price system, whereby the sales prices are fixed by an administrative body with the objective of arriving at fair market prices. Income generated by gas sales is, with very few exceptions, assessed on actual sales prices.

Although certain important deductible expenses are dealt with in the PTA, the deductibility of expenses for purposes of the special petroleum tax is based on the general rules in the GTA. The timing of deductions for tax purposes generally follows the realisation principle, i.e. when the expense is unconditionally incurred by the taxpayer. Provisions in the accounts based on prudent accounting principles are generally not deductible for tax purposes.

Financial items, such as interest income and expenses and currency losses and gains etc. are taxable. However, interest expenses and foreign currency items relating to interest-bearing debt instruments are treated separately from other financial items. Such costs fall within the offshore tax regime, meaning that they are deductible against income taxed at 78 per cent. However, the amount of such costs deductible against income falling within the offshore tax regime is capped as follows:

$$\text{Offshore tax deduction} = (\text{Interest cost} + \text{exchange gain/loss}) \times 50\% \times \frac{\text{Tax value offshore assets 31.12}}{\text{Average interest-bearing debt}}$$

Any such costs in excess of this cap together with other financial items fall within the ordinary corporate tax regime, meaning that they are deductible against income taxed at 25 per cent. If the taxpayer does not have any income which is taxed under the ordinary corporate tax regime from which the excess costs can be deducted, it may deduct an amount from its offshore income but only so as to give it an effective deduction against 25 per cent tax, and not against 78 per cent tax.

For general income tax purposes, depreciation deductions are permitted under a reducing balance system. For petroleum tax purposes depreciations of production installations are permitted under a straight-line basis at a rate of 16 2/3 per cent annually from the year in which the investments takes place, i.e. a deprecation over 6 years. In addition to the depreciation allowance offered, an uplift of 5.5 per cent pr. year is granted in the special tax basis for a four-year period for investments in production and pipeline facilities.

Hence, a licensee on the NCS that is subject to Norwegian taxation will be entitled to tax deductions with regard to exploration and production costs (running expenses, net financial items, depreciations and uplift) and transportation costs (tariff payments). Losses for tax purposes may be carried forward indefinitely. Interest is added for losses incurred in 2002 and subsequent years. The calculated interest is added to loss carry forward at the end of each year.

Refund of Tax Value of Exploration Cost

Companies not in a tax position may annually claim a refund from the State of the tax value of direct and indirect costs, except financial charges, incurred in exploration for petroleum resources. The tax value is set to the total of direct and indirect costs multiplied by the tax rate, currently 78 per cent. The refund will reduce the tax loss carry forward correspondingly. The amount of exploration costs may not exceed the annual net loss from the petroleum activities of the taxpayer, to ensure that the costs are not already set off against taxable income.

Transfer of License Interest

All (direct or indirect) assignments of petroleum production licenses on the NCS are subject to the approval by the MPE under the Petroleum Act section 10-12 and of the MoF under the PTA section 10. In Regulations dated 1 July 2009 the MoF has decided that certain, typical, transactions for which the PTA section 10 applies shall be approved as such, on terms set out in the regulations, without any processing of applications, provided that the parties submit certain information to the MoF and the oil taxation authorities.

For transactions not covered by said Regulations, one would still have to apply for an approval from the MoF. The MoF may stipulate specific conditions, which also may deviate from the general tax legislation. The guiding principle for approval of transactions is that they should be revenue neutral to the State, i.e. that the total anticipated tax payments of the buyer and the seller before and after the transaction remain unchanged. Practice concerning such transactions has undergone considerable changes over the years, but will now follow the Regulations issued by the MoF on 1 July 2009.

According to said Regulations, the existing tax balances (depreciation and uplift) will (as the main rule) be transferred from the seller to the buyer with the assets. Thus, there will be no step up of the tax balances as a result of the transaction.

8. SELECTED FINANCIAL INFORMATION FOR THE COMPANY

The following selected financial information has been extracted from the Group's audited financial statements as of and for the years ended 31 December 2015, 2014 and 2013 and the Group's unaudited interim financial statements for the three and six months ended 30 June 2016 and 2015. The historical results of the Group 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 the Group, see Section 1 "Risk Factors". The following summary of consolidated financial data should be read in conjunction with the other information contained in this Information Memorandum, including the Annual Financial Statements of the Group and the notes therein and the Interim Financial Statements, which have been incorporated in this Information Memorandum by reference; see Section 11 "Incorporation by Reference; Documents on Display".

8.1 Accounting Principles

The Company prepares its financial statements in accordance with the International Financial Reporting Standards (IFRS) adopted by EU and the Norwegian Accounting Act.

During the periods 2013 – 2016, some changes were made to the originally issued financial statements regarding presentation of certain comparative items in the income statement, statement of financial position and cash flow statement. In the tables below, the presentation principles from the originally issued financial statements have been applied. This does not apply for 2013 numbers, where comparable figures from the 2014 annual report have been used, due to the change in presentation currency to USD in 2014.

8.2 Selected Income Statement Information

The table below sets out a summary of the Group's income statement information for the three and six months ended 30 June 2016 and 2015 and for the years ended 31 December 2015, 2014 and 2013.

USD thousands	**For the Three Months Ended 30 June**		**For the Six Months Ended 30 June**		**For the Year Ended 31 December**		
	2016	**2015**	**2016**	**2015**	**2015**	**2014**	**2013**
Petroleum revenues......................	271,272	336,084	472,040	659,832	1,158,683	411,996	158,782
Other operating revenues..............	-15,608	1,152	-11,527	1,582	63,119	52,235	1,824
Total operating revenues..............	**255,665**	**337,236**	**460,513**	**661,414**	**1,221,802**	**464,230**	**160,606**
Exploration expenses	36,214	24,949	72,329	39,471	76,404	157,578	278,554
Production costs..........................	39,116	50,686	73,490	90,035	141,000	66,754	42,474
Payroll expenses..........................	–	–	–	–	–	–17,042	6,470
Depreciations and amortization	120,264	117,354	234,582	239,578	480,959	160,254	80,063
Impairments..............................	-19,644	–	18,319	52,773	430,468	346,420	113,346
Other operating expenses	5,410	22,550	10,741	36,947	51,608	49,193	18,698
Total operating expenses..............	**181,360**	**215,539**	**409,461**	**458,805**	**1,180,438**	**763,157**	**539,605**
Operating profit/loss....................	**74,305**	**121,697**	**51,052**	**202,609**	**41,364**	**–298,927**	**–378,999**
Interest income...........................	1,523	913	2,340	1,175	3,098	7,009	6,934
Other financial income..................	10,437	8,135	41,194	55,759	65,385	19,435	168
Interest expenses.........................	21,125	25,204	41,826	51,668	109,125	83,845	51,359
Other financial expenses................	19,786	42,367	23,040	63,535	114,328	19,296	9,844
Net financial items......................	**-28,951**	**–58,523**	**-21,331**	**–58,269**	**–154,971**	**–76,697**	**–54,101**
Profit/loss before taxes................	**45,353**	**63,174**	**29,720**	**144,340**	**–113,607**	**–375,624**	**–433,100**
Taxes (+)/tax income(-)	39,046	55,897	-8,821	134,624	199,045	–96,485	–339,753
Net profit/loss............................	**6,308**	**7,277**	**38,541**	**9,716**	**–312,652**	**–279,139**	**–93,347**
Weighted average no. shares outstanding and fully diluted........	202,618,602	202,618,602	202,618,602	202,618,602	202,618,602	165,811,098	140,707,363
Profit/loss after taxes per share (in USD)	0.03	0.04	0.19	0.05	–1.54	–1.68	–0.66
Statement of comprehensive income							
Profit/loss for the period	6,308	7,277	38,541	9,716	–312,652	–279,139	–93,347

USD thousands	For the Three Months Ended 30 June		For the Six Months Ended 30 June		For the Year Ended 31 December		
	2016	**2015**	**2016**	**2015**	**2015**	**2014**	**2013**
Items that will not be reclassified over profit and loss							
Exchange differences on translation to USD....................................	—	—	-59	—	—	—43,069	—53,906
Actuarial gain/loss pension plan.......	—	—	—	—	17	—897	152
Total comprehensive income in period, attributable to equity holders of the parent company....	**6,308**	**7,277**	**38,482**	**9,716**	**—312,636**	**—323,105**	**—147,101**

8.3 Selected Financial Position Information

The table below sets out a summary of the Group's financial position information as of 30 June 2016 and as of 31 December 2015, 2014 and 2013.

USD thousands	As of 30 June	As of 31 December		
	2016	**2015**	**2014**	**2013**
Assets				
Intangible assets				
Goodwill	739,383	767,571	1,186,704	52,784
Capitalized exploration expenditures	316,913	289,980	291,619	337,969
Other intangible assets	609,943	648,030	648,788	106,235
Deferred tax asset	–	–	–	103,625
Tangible fixed assets				
Property, plant and equipment	3,305,081	2,979,434	2,549,271	436,834
Financial assets				
Long-term receivables	1,724	3,782	8,799	20,618
Other non-current assets	28,090	–	–	–
Long-term derivatives	13,545			
Other non-current assets	2,287	12,628	3,598	46,912
Total non-current assets	**5,016,966**	**4,701,425**	**4,688,778**	**1,104,976**
Inventories				
Inventories	35,816	31,533	25,008	6,720
Receivables				
Accounts receivable	43,572	85,546	186,461	22,062
Other short-term receivables	227,306	105,190	184,592	82,091
Other current financial assets	2,951	2,907	3,289	3,957
Tax receivables	206,749	126,391	–	231,972
Short-term derivatives	6,774	45,217	–	–
Cash and cash equivalents				
Cash and cash equivalents	68,393	90,599	296,244	280,942
Total current assets	**591,561**	**487,384**	**695,594**	**627,745**
Total assets	**5,608,527**	**5,188,809**	**5,384,372**	**1,732,720**
Equity and liabilities				
Equity				
Share capital	37,530	37,530	37,530	27,656
Share premium	1,029,617	1,029,617	1,029,617	564,736
Other equity	-689,639	–728,121	–415,485	–68,292
Total equity	**377,508**	**339,026**	**651,662**	**524,100**
Non-current liabilities				
Pension obligations	–	1,638	2,021	10,933
Deferred taxes	1,439,940	1,356,114	1,286,357	–
Abandonment provision	445,085	412,805	483,323	136,188
Provisions for other liabilities	1,204	–	12,044	128
Bonds	515,486	503,440	253,141	406,592
Other interest-bearing debt	2,336,361	2,118,935	2,037,299	334,814
Long-term derivatives	38,117	62,012	5,646	8,129
Current liabilities				
Short-term loan	–	–	–	78,579
Trade creditors	74,879	51,078	152,258	74,368
Accrued public charges and indirect taxes	7,343	9,060	6,758	3,876
Tax payable	–	–	189,098	–
Short-term derivatives	230	13,506	25,224	–
Abandonment provision	17,504	10,520	5,728	24,225
Other current liabilities	354,870	310,675	273,813	130,789
Total liabilities	**5,231,019**	**4,849,783**	**4,732,710**	**1,208,620**
Total equity and liabilities	**5,608,527**	**5,188,809**	**5,384,372**	**1,732,720**

8.4 Selected Changes in Equity Information

The table below sets out a summary of the Group's changes in equity information for the six months ended 30 June 2016 and for the years ended 31 December 2015, 2014 and 2013.

USD thousands			Other equity					
				Other comprehensive income				
	Share capital	Share premium	Other paid-in capital	Actuarial gains/ (losses)	Foreign currency translation reserves	Retained earnings	Total other equity	Total equity
Equity as of 1 January 2013	**27,656**	**564,736**	**573,083**	**–375**	**5,573**	**–499,471**	**78,809**	**671,201**
Total loss for the period 1.1.2013 – 31.12.2013...				152	–53,906	–93,347	–147,101	–147,101
Equity as of 31.12.2013..............	**27,656**	**564,736**	**573,083**	**–223**	**–48,334**	**–592,818**	**–68,292**	**524,100**
Rights issue.................	9,874	469,249			–24,350		–24,350	454,773
Transaction costs, rights issue...............		–4,368			261		261	–4,107
Total loss for the period 1.1.2014 – 31.12.2014...				–897	–43,069	–279,139	–323,105	–323,105
Settlement of defined benefit plan..............				1,016		–1,016		
Equity as of 31.12.2014..............	**37,530**	**1,029,617**	**573,083**	**–105**	**–115,491**	**–872,972**	**–415,485**	**651,662**
Total comprehensive income – 1.1.2015 – 31.12.2015	–	–	–	17	–	–312,652	–312,636	–312,636
Equity as of 31.12.2015..............	**37,530**	**1,029,617**	**573,083**	**–88**	**–115,491**	**–1,185,625**	**–728,121**	**339,026**
Total comprehensive income – 1.1.2015 – 31.12.2015	–	–	–	–	-59	38,541	38,482	38,482
Equity as of 30.06.2016..............	**37,530**	**1,029,617**	**573,083**	**-88**	**-115,550**	**-1,147,083**	**-689,639**	**377,508**

8.5 Selected Cash Flow Information

The table below sets out a summary of the Group's cash flow information for the three and six months ended 30 June 2016 and 2015 and for the years ended 31 December 2015, 2014 and 2013.

USD thousands	For the Three Months Ended 30 June		For the Six Months Ended 30 June		For the Year Ended 31 December		
	2016	**2015**	**2016**	**2015**	**2015**	**2014**	**2013**
Cash flow from operating activities							
Profit/loss before taxes	43,353	63,174	29,720	144,340	–113,607	–375,624	–433,100
Taxes paid during the period	–1,268	–126,364	-1,268	–190,506	–320,618	–109,068	–4,524
Tax refund during the period	–	–	–	–	87,662	190,532	224,337
Depreciation	120,264	117,354	234,582	239,578	480,959	160,254	80,063
Net impairment losses	-19,644	–	18,319	52,773	430,468	346,420	113,346
Accretion expenses	6,063	6,551	11,875	12,947	26,351	12,410	7,277
Interest expenses	39,599	–	77,234	–	127,620	85,107	–
Interest paid	-47,481	–	-76,913	–	–124,276	–83,910	–
Gain/loss on licence swaps without cash effect	–	–	–	–	–	–49,765	125
Changes in derivatives	34,876	3,038	-1,014	–8,746	–793	10,616	540
Amortization of interest expenses and arrangement fee	4,287	5,077	7,396	11,679	17,480	26,711	15,052
Amortization of fair value of contracts assumed in the Marathon transaction	–	–2,878	–	–2,878	–2,878	–	–
Expensed capitalized dry wells	17,938	10,185	34,389	9,876	11,682	99,061	195,770
Changes in inventories, accounts payable and receivables	-161,403	–86,177	-60,623	–261,163	–13,060	–530,150	24,126
Changes in abandonment liabilities through income statement	–	–	–	–	–1,569	–1,952	–
Changes in other current balance sheet items	88,695	53,407	49,414	316,349	81,048	482,148	–67,200
Net cash flow from operating activities	**127,279**	**43,366**	**323,110**	**324,250**	**686,467**	**262,791**	**155,812**
Cash flow from investing activities							
Payment for removal and decommissioning of oil fields	-1,714	–2,042	-3,020	–3,176	–12,508	–14,087	–6,251
Disbursements on investments in fixed assets	-278,872	–212,561	-488,151	–451,463	–917,150	–583,200	–254,502
Acquisition of Marathon Oil AS (net of cash acquired)	–	–	–	–	–	–1,513,591	–
Acquisitions of Premier Oil Norge AS (net of cash acquired)	–	–	–	–	–125,600	–	–
Acquisition of Svenska Petroleum Exploration AS	–	–	–	–	–	–	–
Disbursements on investments in capitalized exploration expenditures and other intangible assets	-44,039	–10,709	–65,267	–31,914	–113,051	–164,128	–231,230
Sale of tangible fixed assets and licences	–	–	–	–	–	8,862	14,714
Net cash flow from investing activities	**-324,625**	**–225,312**	**-556,438**	**–486,553**	**– 1,168,310**	**– 2,266,144**	**–477,270**
Cash flow from financing activities							
Net proceeds from equity issuance	–	–	–	–	–	474,755	–
Repayment of short-term debt	–	–	–	–	–70,938	–162,434	–255,232
Repayment of bond (detnor 01)	–	–	–	–	–	–87,536	–
Repayment of long-term debt	–	–330,000	–	–330,000	–330,000	–1,147,934	–371,806
Arrangement fee	–	–11,313	–	–11,313	–14,380	–67,350	–
Proceeds from issuance of long-term debt	112,328	300,000	–	400,000	700,000	2,897,354	804,713
Proceeds from issuance of short-term debt	–	–	212,328	–	–	116,829	238,217

USD thousands	For the Three Months Ended 30 June		For the Six Months Ended 30 June		For the Year Ended 31 December		
	2016	2015	2016	2015	2015	2014	2013
Net cash flow from financing activities	**112,328**	**−41,313**	**212,328**	**58,687**	**284,683**	**2,023,684**	**415,892**
Net change in cash and cash equivalents	**-85,019**	**−223,258**	**-20,999**	**−103,616**	**−197,160**	**20,331**	**94,433**
Cash and cash equivalents at the start of period	154,618	411,691	90,599	296,244	296,244	280,942	207,348
Effect of exchange rate fluctuation on cash held	-1,206	−504	-1,206	−4,699	−8,485	−5,029	−20,839
Cash and cash equivalents at end of period	**68,393**	**187,928**	**68,393**	**187,928**	**90,599**	**296,244**	**280,942**
Specification of cash equivalents at end of period							
Bank deposits and cash	62,411	182,802	62,411	182,802	86,201	291,346	278,337
Effect of exchange rate fluctuation on cash held	5,983	5,126	5,983	5,126	4,398	4,897	2,605
Cash and cash equivalents at end of period	**68,393**	**187,928**	**68,393**	**187,928**	**90,599**	**296,244**	**280,942**

8.6 Other Selected Financial and Operating Information

The table below sets out certain other unaudited non-IFRS key financial and operating information for the Company:

	Unit	As of or for the Six Months Ended June 30, 2016	As of or for the Year Ended December 31, 2015
EBITDA[(1)]	USDk	303,953	952,790'
Earnings per share (EPS)[(2)]	USD	0,19	-1,54
Net interest-bearing debt[(3)]	USDk	2,789,437	2,536,174
Equity ratio[(4)]	—	6,7%	6,5%
Debt-to-equity ratio[(5)]	—	13,9	14,3
Interest coverage ratio[(6)]	—	7,3	8,7
Production cost per barrel[(7)]	USD/boe	7	6
Depreciation per barrel[(8)]	USD/boe	21	22

(1) EBITDA is short for earnings before interest and other financial items, taxes, depreciation and amortisation and impairments.

(2) Earnings per share (EPS) is net profit divided by number of shares outstanding.

(3) Net interest bearing debt, which is book value of interest bearing debt less cash and cash equivalents excluding debt service reserves and rental deposit accounts.

(4) Total shareholders' equity divided by total assets, multiplied by 100.

(5) Total liabilities to shareholders equity.

(6) EBITDA (being operating profit) to interest expenses.

(7) Production cost per boe is production cost divided by number of barrels of oil equivalents produced in the corresponding period.

(8) Depreciation per boe is depreciation divided by number of barrels of oil equivalents produced in the corresponding period.

9. UNAUDITED PRO FORMA FINANCIAL INFORMATION

9.1 Cautionary Note Regarding the Unaudited Pro Forma Financial Information

The following tables set out unaudited pro forma financial information for the Group as of and for the year ended 31 December 2015 and is prepared under the assumption that the Transaction will close as described.

The unaudited pro forma financial information has been prepared solely to show how the Transaction would have impacted on the consolidated income statement for the Group for the twelve months ended 31 December 2015 had the Transaction occurred on 1 January 2015, and the consolidated balance sheet as of 31 December 2015 had the Transaction occurred on 31 December 2015. The Transaction is expected to be completed on or about 30 September 2016.

Although the unaudited pro forma financial information is based on estimates and assumptions based on current circumstances believed to be reasonable, actual results could have materially differed from those presented herein. There is a greater degree of uncertainty associated with pro forma figures than with actual reported financial information. The unaudited pro forma financial information has been prepared for illustrative purposes only and, because of its nature, the pro forma financial information addresses a hypothetical situation and, therefore, does not represent the company's actual financial position or results.

The unaudited pro forma financial information has been compiled to comply with the requirements as set forth in Section 3.5 of the Continuing Obligations by reference to Annex II of Commission Regulation (EC) no. 809/2004 implementing Directive 2003/71/EC of the European Parliament and of the Council of 4 November 2003 regarding information contained in prospectuses as well as the format, incorporation by reference and publication of such prospectuses and dissemination of advertisements, which pursuant to the Continuing Obligations apply correspondingly to information memorandums such as this Information Memorandum.

9.2 Independent Assurance Report on Unaudited Pro Forma Financial Information

With respect to the unaudited pro forma financial information included in this Information Memorandum, KPMG AS has applied assurance procedures in accordance with ISAE 3240 *Assurance Engagement to Report on Compilation of Pro Forma Financial Information Included in a Prospectus* in order to express an opinion as to whether the unaudited pro forma financial information has been properly compiled on the basis stated, and that such basis is consistent with the accounting policies of the Company; see Appendix B (*Independent Practitioner's Assurance Report on the Compilation of Pro-Forma Financial Information included in an Information Memorandum*). There are no qualifications to this assurance report.

9.3 Sources of the Unaudited Pro Forma Financial Information

The historical financial information for the Company used for compilation of the pro forma income Statement has been extracted from the Annual Financial Statements for the Company as of and for the year ended 31 December 2015. These documents are incorporated by reference to this Information Memorandum; See Section 11 "Incorporation by Reference; Documents on Display".

The financial information of BP Norge has been extracted from the Annual Financial Statements for BP Norge as of and for the year ended 31 December 2015 prepared in accordance with Norwegian generally accepted accounting principles ("**NGAAP**") and in compliance with the 1998 Accounting Act. The Financial Statements for BP Norge are set out in Appendix C.

Certain reclassifications have been done to conform BP Norge's 2015 financial statement presentation to that of the Company. The tables below show the BP Norge 2015 financial statement presented in NOK, the recalculation to USD and the adjustments made to comply with the form of the financial statement presented by the Company. The currency rate for conversion to USD is the average 2015 (8.0739) rate for the income statement and the year end 2015 rate (8.8090) for the statement of financial position.

Income Statement

USD thousands *31 December 2015*	NOK	USD	Adjusted presentation*
Petroleum reserves	7 899 328	978 378	978 378
Other operating income	35 321	4 375	4 375
Total operating income	**7 934 649**	**982 753**	**982 753**
Exploration expenses			8 774
Change in over/underlift of petroleum	-46 724	-5 787	
Transport costs	621 963	77 034	
Payroll and payroll-related expenses	885 453	109 669	
Depreciation and amortization	3 107 633	384 899	384 899
Impairments	-	-	-
Production costs	2 037 468	252 352	424 494
Other operating expenses	759 679	94 091	94 091
Removal and decommissioning	1 392 401	172 457	172 457
Total operating expenses	**8 757 873**	**1 084 714**	**1 084 714**
Operating profit (loss)	**-823 224**	**-101 961**	**-101 961**
Interest income from group companies	17 601	2 180	
Other interest income	2 327	288	2 468
Other financial income			33 459
Interest expenses to group companies	-344 141	-42 624	
Other interest expenses	-6 638	-822	-43 446
Net currency profit/loss	270 144	33 459	
Net financial items	**-60 708**	**-7 519**	**-7 519**
Profit/(loss) before taxes	**-883 933**	**-109 480**	**-109 480**
Taxes(+)/tax income (—)	-583 306	-72 246	-72 246
Net income	**-300 627**	**-37 234**	**-37 234**

* Change in over/underlift, transport costs and payroll expenses have been reclassified to production cost. Exploration expenses have been separated from production cost based on information from BP Norge.

Statement of Financial Position

USD thousands *31 December 2015*	NOK	USD	Adjusted presentation*
Assets			
Intangible assets			
Mineral rights	909 904	103 293	103 293
Long-term operating assets	-	-	
Production plant and pipeline	19 821 845	2 250 181	2 257 272
Capitalised exploration and evaluation expenses	132 672	15 061	15 061
Means of transport machinery and fixtures	62 462	7 091	
Total fixed assets	**20 926 883**	**2 375 625**	**2 375 625**
Current assets			
Inventories	271 699	30 843	30 843
Receivables			
Accounts receivable from customers	69 070	7 841	7 841
Accounts receivable from group companies	2 162 444	245 481	245 481
Other receivables	23 010	2 612	10 620
Under lifting of petroleum	70 544	8 008	
Bank deposits	13 195	1 498	1 498
Total current assets	2 609 962	296 284	296 284
Total assets	**23 536 845**	**2 671 909**	**2 671 909**
Equity and liabilities			
Equity			
Contributed equity			
Share capital	2 000	227	227
Share premium	2 874 000	326 257	326 257
Earned equity			
Other equity	828 048	94 000	94 000
Total equity	**3 704 048**	**420 485**	**420 485**
Liabilities			
Provisions for obligations			
Pension obligations	657 428	74 631	74 631
Deferred taxes	2 443 627	277 401	277 401
Provisions for decommissioning and abandonment	7 529 252	854 723	854 723
Total provisions for obligations	**10 630 307**	**1 206 755**	**1 206 755**
Other long-term liabilities			
Debt to group companies	7 500 000	851 402	851 402
Total other long-term liabilities	**7 500 000**	**851 402**	**851 402**
Short-term liabilities			
Accured public charges and indirect taxes	116 790	13 258	13 258
Tax payable	162 705	18 470	18 470
Debt to group companies	55 282	6 276	
Other short-term liabilities	1 281 431	145 468	161 539
Over lifting of petroleum	86 282	9 795	
Total short-term liabilities	**1 702 490**	**193 267**	**193 267**
Total equity and liabilities	**23 536 845**	**2 671 909**	**2 671 909**

* Change in over/underlift, transport costs and payroll expenses have been reclassified to production cost. Exploration expenses have been separated from production cost based on information from BP Norge.

The Unaudited Pro Forma Financial Information does not include all information required for the financial statements under IFRS, and should be read in conjunction with the Annual Financial Statements as of and for the year ended 31 December 2015 for the Company. The Unaudited Pro Forma Financial Information has been prepared by using the same accounting principles as for the Annual Financial Statements as of and for the year ended 31 December 2015, i.e. IFRS as adopted by the EU.. There were no new standards or interpretations implemented in the first half of 2016 which had a significant impact on the Company's Financial Statements. Please refer to the financial statements for 2015 for description of the accounting policies.

9.4 Unaudited Pro Forma Consolidated Income Statement

The table below sets out the unaudited pro forma consolidated income statement of the Group for the year ended 31 December 2015, as if the Transaction had been completed on 1 January 2015.

Income statement 2015 *USD thousands*	Det norske (IFRS)	BP (NGAAP)	IFRS adjustments	Pro forma adjustments	Notes to IFRS and pro forma adjustments	Pro forma year ending 31 December 2015
Operating revenues and expenses						
Petroleum reserves	1 158 683	978 378	40 034	0	1	2 177 095
Other operating revenues	63 119	4 375	0	0		67 494
Total operating revenues	**1 221 802**	**982 753**	**40 034**	**0**		**2 244 589**
Exploration expenses	76 404	8 774	0	0		85 178
Production costs	141 000	424 494	-5 923	0	1, 2	559 571
Depreciation and amortization	480 959	384 899	-47 512	-127 982	3, 4	690 363
Impairments	430 468	0	0	0		430 468
Provision for decommissioning	0	172 457	-162 301	0	4	10 156
Other operating expenses	51 608	94 091	0	570	6	146 268
Total operating expenses	**1 180 438**	**1 084 714**	**-215 736**	**-127 412**		**1 922 005**
Operating profit (loss)	**41 363**	**-101 961**	**255 770**	**127 412**		**322 584**
Interest income	3 098	2 468	0	0		5 566
Other financial income	65 385	33 459	0	0		98 844
Interest expenses	109 125	43 446	0	-42 624	6	109 947
Other financial expenses	114 328	0	42 319	35 852	4	192 498
Net financial items	**-154 971**	**-7 519**	**-42 319**	**6 772**		**-198 035**
Profit/(loss) before taxes	**-113 607**	**-109 480**	**213 451**	**134 185**		**124 549**
Taxes(+)/tax income (—)	199 045	-72 246	166 492	82 518	7	375 809
Net income	**-312 652**	**-37 234**	**46 959**	**51 667**		**-251 260**

The notes to the unaudited pro forma financial information are an integral part of the unaudited pro forma statement information.

9.5 Unaudited Pro Forma Consolidated Balance Sheet

The table below sets out the unaudited pro forma consolidated balance sheet for the Group as of 31 December 2015, as if the Transaction had been completed on 31 December 2015.

USD thousands *31 December 2015*	Det norske (IFRS)	BP (NGAAP)	IFRS adjustments	Pro forma adjustments	Notes to IFRS and pro forma adjustments	Pro forma as of 31 December 2015
Assets						
Intangible assets						
Goodwill	767 571	0	0	673 783	5	1 441 354
Capitalized exploration expenditures	289 980	15 061	0	-15 061	5	289 980
Other intangible assets	648 030	103 293	0	-93 056	5	658 267
Deferred tax assets			0	1 186 368	5, 7	1 186 368
Total intangible assets	**1 705 581**	**118 354**	**0**	**1 752 035**		**3 575 969**
Tangible fixed assets						
Property, plant and equipment	2 979 434	2 257 272	459 452	-1 358 697	4, 5	4 337 460
Total tangible fixed assets	**2 979 434**	**2 257 272**	**459 452**	**-1 358 697**		**4 337 460**
Financial assets						
Long term receivables	3 782		0	0		3 782
Other non-current assets	12 628		0	0		12 628
Total financial fixed assets	**16 410**	**0**	**0**	**0**		**16 410**
Total non-current assets	**4 701 425**	**2 375 625**	**459 452**	**393 338**		**7 929 840**
Inventories						
Inventories	31 533	30 843	0	0		62 376
Total inventories	**31 533**	**30 843**	**0**	**0**		**62 376**
Receivables						
Account receivables	85 546	7 841	0	245 481	8	338 868
Accounts receivable—group companies	0	245 481	0	-245 481	8	0
Other short term receivables	105 190	10 620	12 446	0	1	128 256
Other current financial assets	2 907		0	0		2 907
Tax receivables	126 391		0	0		126 391
Short-term derivatives	45 217		0	0		45 217
Total current receivables	**365 251**	**263 942**	**12 446**	**0**		**641 639**
Cash and cash equivalents	90 599	1 498	0	98 000	5	190 097
Total current assets	**487 384**	**296 284**	**12 446**	**98 000**		**894 113**
Other assets			0	0		0
Total assets	**5 188 809**	**2 671 909**	**471 897**	**491 338**		**8 823 953**
Equity and liabilities						
Equity						
Share capital	37 530	227	0	15 339	5,6	53096
Share premium	1 029 617	326 257	0	1 191 970	5,6	2 547 844
Other equity	-728 121	94 000	-7 394	-87 176	5,6	-728 691
Total equity	**339 026**	**420 485**	**-7 394**	**1 120 134**		**1 872 250**

USD thousands 31 December 2015	Det norske (IFRS)	BP (NGAAP)	IFRS adjustments	Pro forma adjustments	Notes to IFRS and pro forma adjustments	Pro forma as of 31 December 2015
Provisions for liabilities						
Pension obligations................	1 638	74 631	58 115	0	2	134 384
Deferred taxes.....................	1 356 114	277 401	-26 217	-25	7	1 607 274
Abandonment provision	412 805	854 723	447 394	221 961	4, 5	1 936 882
Total provisions...................	**1 770 557**	**1 206 755**	**479 292**	**221 936**		**3 678 540**
Non current liabilities						
Bonds	503 440	0	0	0		503 440
Other interest-bearing debt.....	2 118 935	851 402	0	-851 402	5,6	2 118 935
Long-term derivatives	62 012	0	0	0		62 012
Total non-current liabilities ...	**2 684 387**	**851 402**	**0**	**-851 402**		**2 684 387**
Current liabilities						
Trade creditors	51 078	0	0	6 276	8	57 354
Accrued public charges and indirect taxes....................	9 060	13 258	0	0		22 318
Taxes payable......................	0	18 470	0	0		18 470
Short-term derivatives	13 506		0	0		13 506
Short-term debt to group companies........................		6 276	0	-6 276	8	0
Abandonment provision	10 520		0	0		10 520
Other current liabilities..........	310 675	155 263	0	670	6	466 608
Total current liabilities	**394 839**	**193 267**	**0**	**670**		**588 776**
Total liabilities.....................	**4 849 783**	**2 251 424**	**479 292**	**-628 796**		**6 951 703**
Total liability and equity	**5 188 809**	**2 671 909**	**471 897**	**491 337**		**8 823 953**

The notes to the unaudited pro forma financial information are an integral part of the unaudited pro forma balance sheet information.

Notes to the unaudited IFRS and unaudited pro forma adjustments

BP Norge AS has historically presented its statutory financial statements in accordance with NGAAP. In connection with the compilation of the unaudited pro forma financial information, unaudited differences between IFRS and NGAAP were identified and the resulting adjustments are presented in a separate column the unaudited pro forma financial information and described in the notes below.

When applicable, the adjustments related to pro forma financial information are shown separately in each note below.

All amounts are expressed in USD 1,000, unless otherwise specified.

1) *Revenue recognition*

The Company recognizes revenues from petroleum products on the basis of the Company's ideal share of production during the period, regardless of actual sales (entitlement method). BP Norge has recognised revenues when title passes to the customer at the point of delivery based on the contractual terms of the sales agreements (sales method).

Hence, the BP Norge revenues have been adjusted to reflect the ideal share of production instead of the actual sales. The costs related to the adjusted revenues were also adjusted.

Income statement	2015
Increased revenue	40,034
Increased cost	6,527
Net impact before tax	33,507

The different accounting principle on revenue also impacts the valuation of over/underlift. The Company set the value of over/underlift at the estimated sales value, minus estimated sales costs. For BP Norge, overlift is valued at production cost, while underlift is valued to the lowest of sales value and production cost.

Statement of financial position:	
Net increase underlift asset 31 December 2015	12,446

All adjustments will have continuing impact.

2) Pensions

BP Norge has applied an NGAAP specific rule (NRS 6), allowing that accumulated losses of the benefit obligation are amortised over the remaining service period of active plan participants. This method is not in accordance with IAS 19, where any actuarial gains and losses need to be recognised immediately in other comprehensive income. In addition, an adjustment is made to reflect the different assumptions which are closer to the Company's assumptions.

The actuarial assumptions are not identical for the two companies, but the impact from the deviations is not material for the pro forma financial information.

The total adjustment on the pension obligation as of 31 December 2015 amounts to an increase of 58,115 according to the above mentioned actuarial assumptions, and is reflected in the pro forma statement of financial position. Regarding the Income Statement, reversal of amortisation of actuarial losses under NGAAP amounts to 12,449. The adjustments will have continuing impact.

3) Depreciation

Both the Company and BP Norge apply unit of production method ("**UOP**") as the depreciation method for oil and gas fields. However, the Company's UOP is based on proved and probable reserves while BP Norway applies only proved reserves in its calculation of depreciation.

The BP Norge depreciation is therefore adjusted as follows:

Income statement:	2015
Decreased depreciation based on 2P reserves	(93,909)
Depreciation of ARO asset (see note on decommissioning below)	46,397
Net impact before tax	(47,512)
Pro forma adjustments	
	2015
Depreciation field excess values	(127,982)

The depreciation was recorded based on the excess values identified in note 5 below using the unit of production method. The deprecation has been calculated based on the depreciation rate/barrel in the preliminary PPA and the production in 2015.

All the adjustments will have continuing impact.

4) Decommissioning and removal costs

In accordance with IFRS the Company records decommissioning and asset retirement obligations ("**ARO**") based on the net present value of the future related expenses. A corresponding asset is capitalised as a tangible fixed asset, and depreciated using the unit of production method. Changes in the time value (net present value) of the obligation related to decommissioning and removal accretion are charged to the income statement as financial expenses, and increase the liability related to future decommissioning and removal expenses. Changes in the best estimate for expenses related to decommissioning and removal are recognised in the statement of financial position. The discount rate used in the calculation of the fair value of the decommissioning and removal obligation is the risk-free rate with the addition of a credit risk element.

BP Norge has accrued the estimated costs of decommissioning and removal of producing facilities using the UOP method based on proved reserves. As a result the tangible fixed ARO asset and the ARO obligation have been calculated for BP Norge including related depreciation and accretion.

Income statement:	2015
Adjusted provision for decommissioning costs	(162,301)
Depreciation of ARO asset	46,397
Accretion	42,319
Statement of financial position:	
Long-term provision for ARO as of 31 December 2015	1,302,116
BP Norge AS booked ARO as of 31 December 2015	854,723
GAAP adjustment	447,394
Recognised ARO asset as of 31 December 2015	459,452
Discount rate applied	3,91% - 6,11%

The initial amount presented as provision for decommissioning in the NGAAP Income Statement of BP Norge for 2015 was 172,457. The adjustment of 162,301 leaves 10,156 on that line item. This is related to change in removal estimates for Gassled assets, as well as removal obligations for fields previously sold by BP Norge. As shipper of gas through the Gassled infrastructure, BP Norge has a contractual obligation to cover a proportionate share of the removal of the Gassled facilities. Since BP Norge is not a Gassled owner, no corresponding removal asset is recognised and the cost will be charged directly to the Income Statement based on shipped gas for the year.

Pro forma adjustments

In the purchase price allocation ("**PPA**") as further described in note 5 below, the Company has applied a different estimate for decommissioning cost than BP Norge. This results in an increased provision of 370,038 with a corresponding asset as of 31 December 2015. The asset, along with the excess value for producing licenses, is depreciated using the UOP method based on proved and probable reserves. The calculated impact on depreciation and accretion in the income statement is as follows:

Income statement:	2015
Depreciation of negative excess value	-127,982
Accretion expense	35,852

The fair value of the fixed assets (post tax) identified in the PPA is less than the fixed assets value in BP Norge (pretax). Hence, the adjustment above decreases the depreciation originally charged to the BP Norge financial statements.

All the adjustments will have continuing impact.

5) *Purchase Price Allocation – PPA*

Pro forma adjustments

The Company has for the purpose of the pro forma financial information provisionally performed an allocation of the cost of the business combinations to the assets acquired and liabilities and contingent liabilities assumed in accordance with IFRS 3. This allocation has formed the basis for the amortisation and depreciation charges in the Pro Forma Income Statements and the presentation in the Pro Forma Statement of Financial Position. The Purchase Price Allocation applied in the Pro Forma calculations was done in July 2016.

The measurement of the shares consideration equals the share price of the Company at the time of closing of the Transaction. This has been estimated to NOK 100 per share, resulting in a total value of shares of 1 534 MUSD applying the year end 2015 USD/NOK rate. The nominal value of each share is NOK 1. In addition, the Company will pay a total cash consideration of USD 242 million for the shares in BP Norge. Net book value in BP Norge as of 31 December 2015, after the IFRS adjustments is USD 413 million, resulting in an excess of the fair value over the net book value of USD 1,363 million.

The Company has provisionally determined that the excess value based on the purchase price compared to book values as of 31 December 2015 primarily relates to licenses related to producing properties, deferred taxes and goodwill. As there exists no pre-tax market for oil and gas assets in Norway, cf. the PTA section 10, no tax amortisation benefit is calculated. The final allocation may significantly differ from this allocation and this could materially have affected the depreciation and amortisation of excess values in the pro forma income statement and the presentation in the pro forma statement of financial position. The main uncertainty relates to fair value of the licenses.

The historical depreciation in BP Norge has been based on proved reserves, and for pro forma purposes the opening book values have not been adjusted to reflect depreciation based on proved and probable reserves. Going forward, the excess value will be depreciated in accordance with UOP based on proved and probable reserves in line with the reserve base applied for the Company's other oil and gas assets.

Goodwill will not be depreciated, but will be subject to yearly impairment test in accordance with IAS 36. No impairment is recognised in the pro forma financial information.

Provisional allocation of excess value	MUSD
Value of licenses, including decommissioning assets	-1,467
Cash received	340*
Increased decommissioning liability	-221
Intercompany loan to be repaid	851
Goodwill	674
Deferred tax asset (78% rate)	1,186
Total excess value	1,363

*The cash received arise from capital injections made by the seller prior to closing, in accordance with the transaction agreement.

The fair values of these assets and liabilities have been determined on a preliminary basis and is subject to change pending additional information that may become available prior to or upon completion of the transaction. The split between the various assets may subsequently change after the completion of the purchase price allocation. If more of the cost of the business combination should be allocated to producing properties the pro forma income statements would have shown higher amortisation expenses.

The negative excess value for mineral licenses related to producing properties including decommissioning asset is depreciated using the UOP method estimated based on the preliminary purchase price allocation. This resulted in less amortisation of USD 128 million in 2015 based on the historical actual production in those periods (see note Decommissioning and removal costs above).

All these adjustments will have continuing impact.

6) Transaction Costs, Financing and Equity

Pro forma adjustments

The transaction costs to be expensed and unrelated to equity increase are estimated to USD 570 thousand. These are not tax deductible and are expensed in the Unaudited Pro Forma Income Statements and included in the pro forma balance sheet as a reduction in other equity and a corresponding increase in other current liabilities. This pro forma adjustment will not have continuing impact.

The intercompany loan in BP Norge, amounting to 851,402, will be settled as part of the Transaction, as if the loan had been non-existent as of 1 January 2016. The related interest expense for 2015 of 42,624 has been adjusted accordingly. This pro forma adjustment will have continuing impact.

The cost related to capital increase is estimated to USD 75 thousand (100 net of 25 % tax) and is recorded against other paid in capital in the Pro Forma Statements of Position. This pro forma adjustment will not have continuing impact.

7) Tax

Each GAAP- and pro forma–adjustment is charged with the applicable tax rate. For 2015 the statutory tax rate was 27% and the special petroleum tax rate was 51%. The corresponding rates for 2016 are 25% and 53%.

The Company expects BP Norge and the Company to be consolidated for tax purposes within 2016. As this tax consolidation is not a direct result of the transaction and requires future corporate actions, the tax positions (including taxable income and loss for the financial year 2016) have not been offset for the purpose of the Pro Forma numbers.

8) Reclassification

BP Norge has receivables / payables against BP group companies. As a part of the pro forma adjustments, these amounts are reclassified to external payables / receivables in the Pro Forma Statement of Financial Position. These adjustments will have continuing impact.

10. SELECTED FINANCIAL INFORMATION FOR BP NORGE AS

The following selected financial information has been extracted from the audited consolidated financial statements for BP Norge as of and for the years ended 31 December 2015, 2014 and 2013. The historical results of BP Norge 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 BP Norge, see Section 1 "Risk Factors".

10.1 Accounting Principles

Introduction

The annual accounts of BP Norge AS have been prepared in accordance with Norwegian law, regulations for preparing annual accounts, and the generally accepted accounting principles in Norway.

10.2 Selected Income Statement Information

The table below sets out a summary of the audited income statement of BP Norge for the years ended 31 December 2015, 2014 and 2013.

NOK thousands	For the Year Ended 31 December		
	2015	**2014**	**2013**
Operating income			
Petroleum income	7,899,328	12,377,232	8,507,771
Other income	35,321	91,730	43,843
Total operating income	**7,934,649**	**12,468,962**	**8,551,614**
Operating expenses			
Change in over-/under lifting of petroleum	–46,724	216,193	–261,232
Transport expenses	621,963	670,485	581,287
Payroll expenses	885,453	802,458	674,048
Depreciation and depletion	3,107,633	3,194,905	2,108,654
Impairment	0	7,107,357	0
Production costs	2,037,468	2,005,072	0
Other operating expenses	759,679	894,248	2,867,712
Removal and abandonment	1,392,401	2,482,225	1,760,039
Total operating expenses	8,757,873	17,372,944	7,730,509
Operating profit	**–823,224**	**–4,903,981**	**821,105**
Financial income and expenses			
Interest received from group companies	17,601	18,522	875
Other interest income	2,327	3,620	13,026
Interest paid to group companies	–344,141	–495,692	–595,263
Other interest expenses	–6,638	–7,654	–20,452
Net foreign currency losses/gain	270,144	336,695	8,886
Net financial items	–60,708	–144,508	–592,928
Ordinary profit before tax	**–883,933**	**–5,048,489**	**228,177**
Taxes	–583,306	–3,410,203	110,595
Profit for the year	**–300,627**	**–1,638,286**	**117,582**
Allocated to dividend	0	0	0

10.3 Selected Balance Sheet Information

The table below sets out a summary of the audited balance sheet information of BP Norge as of 31 December 2015, 2014 and 2013.

NOK thousands	As of 31 December		
	2015	**2014**	**2013**
Assets			
Fixed assets			
Intangible assets			
Mineral rights	909,904	909,904	1,106,730
Long-term operating assets			
Production plant and pipeline	19,821,845	22,204,418	29,715,739
Capitalised exploration and evaluation expenses	132,672	109,330	802,481
Means of transport, machinery and fixtures	62,462	70,105	65,641
Total fixed assets	**20,926,883**	**23,293,757**	**31,690,591**
Current assets			
Stocks	271,699	329,076	376,563
Receivables			
Accounts receivable from customers	69,070	5,597	67,578
Accounts receivable from group companies	2,162,444	2,380,220	1,285,315
Tax receivable	0	0	14,961
Other receivables	23,010	392,333	414,016
Under lifting of petroleum	70,544	75,916	153,732
Bank deposits	13,195	2,143	10,500
Total current assets	**2,609,962**	**3,185,286**	**2,322,666**
Total assets	**23,536,845**	**26,479,043**	**34,013,257**
Equity and liabilities			
Equity			
Contributed equity			
Share capital	2,000	2,000	2,000
Share premium	2,874,000	2,874,000	2,874,000
Earned equity			
Other equity	828,048	1,128,675	2,766,961
Total equity	**3,704,048**	**4,004,675**	**5,642,961**
Liabilities			
Provisions for obligations			
Pension obligations	657,428	452,211	328,585
Deferred taxation	2,443,627	3,058,864	6,646,371
Provisions for removal and abandonment	7,529,252	6,947,890	5,075,625
Total provisions for obligations	**10,630,307**	**10,458,965**	**12,050,582**
Other long-term liabilities			
Debt to group companies	7,500,000	10,000,000	13,800,000
Total other long-term liabilities	**7,500,000**	**10,000,000**	**13,800,000**
Short-term liabilities			
Public duties payable	116,790	115,487	108,991
Tax payable	162,705	180,914	-
Debt to group companies	55,282	70,166	805,528
Other short-term liabilities	1,281,431	1,510,458	1,605,195
Over lifting of petroleum	86,282	138,377	0
Total short term-liabilities	**1,702,490**	**2,015,403**	**2,519,714**
Total equity and liabilities	**23,536,845**	**26,479,043**	**34,013,257**

10.4 Selected Cash Flow Information

The table below sets out a summary of the audited cash flow information of BP Norge for the years ended 31 December 2015, 2014 and 2013.

NOK thousands	For the Year Ended 31 December		
	2015	2014	2013
Cash flow from operating activities			
Ordinary profit before taxes	−883,933	−5,048,489	228,177
Taxes paid during the period	−50,140	18,571	197,329
Depreciation, depletion and impairment	3,107,633	10,302,262	2,108,654
Removal and abandonment expenses	1,392,401	2,482,225	1,760,039
Change in short-term receivables and stocks	586,377	−859,346	−840,845
Change in short-term liabilities	−294,703	−711,818	340,568
Change in other accrual items	205,216	123,626	50,326
Actual decommissioning costs	−811,041	−609,960	−224,263
Net cash flow from operating activities	**3,251,810**	**5,697,071**	**3,619,985**
Cash flow to investment activities			
Disbursements for acquisitions of fixed assets	−740,759	−1,905,429	−2,614,611
Net cash flow to investment activities	**−740,759**	**−1,905,429**	**−2,614,611**
Cash flow to financing activities			
Repayment of long-term debt	−2,500,000	−3,800,000	-
Dividend paid	-	-	−1,000,000
Net cash flow to financing activities	**−2,500,000**	**−3,800,000**	**−1,000,000**
Net change in cash and cash equivalents for the period	**11,052**	**−8,357**	**5,375**
Cash and cash equivalents, 1 January	**2,143**	**10,500**	**5,125**
Cash and cash equivalents, 31 December	**13,195**	**2,143**	**10,500**

11. INCORPORATION BY REFERENCE; DOCUMENTS ON DISPLAY

11.1 Cross Reference Table

The Continuing Obligations allow the Company to incorporate by reference information in this Information Memorandum that has been previously filed with the Oslo Stock Exchange or the Norwegian Financial Supervisory Authority in other documents. The Annual Financial Statements for the Group as of and for the years ended 31 December 2015, 2014 and 2013, the audit reports in respect of the Annual Financial Statements and the Interim Financial Statements for the Group as of and for the six months ended 30 June 2016 and 2015 is by this reference incorporated as a part of this Information Memorandum. Accordingly, this Information Memorandum is to be read in conjunction with these documents. The Annual Financial Statements and the related audit reports are available at www.detnor.no/investors/.

The information incorporated by reference in this Information Memorandum should be read in connection with the following cross-reference table. References in the table to “Annex” and “Items” are references to the disclosure requirements as set forth in the Continuing Obligations by reference to such Annex (and Item therein) of Commission Regulation (EC) no. 809/2004 implementing Directive 2003/71/EC of the European Parliament and of the Council of 4 November 2003 regarding information contained in prospectuses as well as the format, incorporation by reference and publication of such prospectuses and dissemination of advertisements, which pursuant to the Continuing Obligations apply correspondingly to information memorandums such as this Information Memorandum.

Minimum Disclosure Requirement for Prospectuses (Annex I)		**Reference Document**	**Page of Reference Document**
Item 16.4	A statement as to whether or not the issuer complies with its country of incorporation’s corporate governance regime(s); and in the event of non-compliance a statement to that effect with an explanation regarding non-compliance.	2015 Annual Report	Page 48—59
Item 20.1	Audited historical financial information covering the latest three financial years, and the audit report in respect of each year prepared according to Regulation (EC) No 1606/2002.	2015 Annual Report 2014 Annual Report 2013 Annual Report	Page 61—111 Page 84—139 Page 79—126
Item 20.4.1	A statement that the historical financial information has been audited. If audit reports on the historical financial information have been refused by the statutory auditors or if they contain qualifications or disclaimers, such refusal or such qualifications or disclaimers must be reproduced in full and the reasons given.	2015 Annual Report 2014 Annual Report 2013 Annual Report	Page 112—113 Page 140—141 Page 127—128
Item 20.6.1	The issuer’s published quarterly information since the date of its last audited financial statements. The interim report is unaudited and has not been reviewed by the Company’s auditor.	2nd Quarter Report 2016	Page 1—36

11.2 Documents on Display

For twelve months from the date of this Information Memorandum, copies of the following documents will be available for inspection at the Company's registered office during normal business hours from Monday through Friday each week (except public holidays):

- The 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 of which is included or referred to in the Information Memorandum.
- The Group's financial statements as of and for the years ending 31 December 2015, 2014 and 2013, and the related auditor reports thereto.
- The Company's interim financial statements as of and for the three and six months ended 30 June 2015 and 2016.
- The historical financial statements of the subsidiaries of the Company as of and for the years ended 31 December 2015 and 2014.
- This Information Memorandum.

12. DEFINITIONS

Capitalised terms used throughout this Information Memorandum shall have the meaning ascribed to such terms as set out below, unless the context require otherwise.

Annual Financial Statements	The audited historical financial statements for the Group as of and for the years ended 31 December 2015, 2014 and 2013.
APA	Awards in Predefined Areas.
ARO	Asset retirement obligations.
boe	Barrels of oil equivalent.
boepd	Barrels of oil equivalent per day.
BPCNAI	BP Corporation North America Inc.
BP Norge AS	BP Norge.
Company	Det norske oljeselskap ASA.
Consideration Shares	The 135,118,469 Shares to be issued to the Sellers as consideration under the Transaction.
Continuing Obligations	Continuing Obligations for Stock Exchange Listed Companies.
Corporate Governance Code	The Norwegian Corporate Governance Code of 30 October 2014.
E&P	Exploration and production.
EC Regulation 809/2004	The Commission Regulation (EC) no. 809/2004 implementing the Prospectus Directive and the format, incorporation by reference and publication of prospectuses and dissemination of advertisements, as amended.
Gassco Guarantee	The Second Guarantee Amendment to the Guarantee of 25 April 2005 entered into by BP Norge, Gassco AS and BPCNAI.
GEO 2015	IEA's Global Energy Outlook 2015.
Group	The Company together with its consolidated subsidiaries.
GTA	The Norwegian General Tax Act of 199.
IAS	International Accounting Standards.
IFRS	International Financial Reporting Standards as adopted by the EU.
Interim Financial Statements	The unaudited historical financial statements for the Group as of and for the six months ended 30 June 2016 and 2015.
IEA	International Energy Agency.
ISIN	International Securities Identification Number.
JOA	Joint operating agreements.
Management	The members of the Company's executive Management.
MoF	Ministry of Finance.
MoL	Ministry of Labour.
MPE	Ministry of Petroleum and Energy.
NCS	Norwegian Continental Shelf.
NEA	Norwegian Environmental Agency.
NGAAP	Norwegian generally accepted accounting principles.
Norwegian Securities Trading Act	The Norwegian Securities Trading Act of 29 2007 no. 75, as amended.
NPD	Norwegian Petroleum Directorate.
Oslo Stock Exchange	Oslo Børs (a stock exchange operated by Oslo Børs ASA).
OTO	Oil Taxation Office.
p.a.	per annum.
PDO	Plan for Development and Operations.
PIO	Plan for Installation and Operation,
PPA	Purchase price allocation.
PRMS	Petroleum Resources Management System.
Prospectus Directive	Directive 2003/71/EC of the European Parliament and the Council of 4 November 2003, as amended, regarding information contained in prospectuses.
PSA	Petroleum Safety Authority.
PTA	Petroleum Tax Act.
RBL	Revolving Borrowing Base Facility.
RCF	Revolving Credit Facility.
Relevant Member State	Each member state of the EEA which has implemented the Prospectus Directive.
Securities Trading Act	The Norwegian Securities Trading Act of 27 June 2007 no. 75.
Sellers	Amoco Norway Oil Company and BP Global Investments Ltd.
Shares	The shares of the Company, each with a nominal value of NOK 1.00.

SPE.. Society of Petroleum Engineer.
Transaction .... The acquisition by the Company of BP Norge.
UOP .... Unit of production method.
VPS .... The Norwegian Central Securities Depository (Nw. *Verdipapirsentralen*).

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APPENDIX A—INDEPENDENT ASSURANCE REPORT ON UNAUDITED PRO FORMA FINANCIAL INFORMATION

KPMG AS
P.O. Box 7000 Majorstuen
Sørkedalsveien 6
N-0306 Oslo

Telephone +47 04063
Fax +47 22 60 96 01
Enterprise 935 174 627 MVA
Internet www.kpmg.no

To the Board of Directors of Det norske oljeselskap ASA

Independent Practitioners Assurance Report on the compilation of Pro Forma Financial Information included in an Information Memorandum

In accordance with the requirements in section 3.5.2.6 of the 'Continuing Obligations of Stock Exchange Listed Companies" issued by The Oslo Stock Exchange (Continuing Obligations) we have completed our assurance engagement to report on the compilation of unaudited pro forma financial information of Det norske oljeselskap ASA (the "Company"). The pro forma financial information consists of the unaudited pro forma consolidated balance sheet and income statement as at and for the year ended 31 December 2015, and related notes as set out in section 9 of the Information Memorandum dated 8 September 2016 (the "Information Memorandum") issued by the Company. The applicable criteria on the basis of which management of the Company has compiled the pro forma financial information are specified in EU Commission Regulation (EC) No 809/2004 which is incorporated in section 7-13 of the Securities Trading Act (Norway) and as described in the Unaudited Pro Forma Financial Information in section 9 of the Information Memorandum.

The unaudited pro forma financial information has been compiled by management of the Company to illustrate the impact of the transaction set out in section 4 of the Information Memorandum on the Company's financial position as at 31 December 2015 as if the transaction had taken place at 31 December 2015, and on the Company's financial performance for the year ended 31 December 2015 as if the transaction had taken place at 1 January 2015. As part of this process, information about the Company's and BP Norge AS's financial position and performance has been extracted by management from their annual financial statements as at and for the year ended 31 December 2015.

The Company's Management's Responsibility

The Company's management is responsible for compiling the pro forma financial information on the basis of EU Commission Regulation (EC) No 809/2004 as required by the Continuing Obligations.

Practitioner's Responsibilities

Our responsibility is to express an opinion as required by Annex II, item 7 of EU Commission Regulation (EC) No 809/2004 which is incorporated in the Securities Trading Act (Norway), about whether the pro forma financial information has been properly compiled, by management of the Company, on the basis described in the Basis of Presentation to the unaudited pro forma consolidated balance sheet and income statement information and that basis is consistent with the accounting policies of the Company.

We conducted our engagement in accordance with International Standard on Assurance Engagements (ISAE) 3420, *Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus*, issued by the International Auditing and Assurance Standards Board. This standard requires that the practitioner comply with ethical requirements and plan and perform procedures to obtain reasonable assurance about whether management of the Company has compiled the pro forma financial information on the basis described in the basis of presentation.

For purposes of this engagement, we are not responsible for updating or reissuing any reports or opinions on any historical financial information used in compiling the pro forma financial information, nor have we, in the course of this engagement, performed an audit or review of the financial information, including any adjustments made to conform accounting policies, or assumptions used in compiling the pro forma financial information. Our work has consisted primarily of comparing the underlying historical financial information used to combine the pro forma financial information to source documentation, assessing documentation supporting any pro forma and other adjustments and discussing the pro forma information with management of the Company.

The purpose of pro forma financial information included in an Information Memorandum is solely to illustrate the impact of a significant event or transaction on unadjusted financial information of the Company as if the event had occurred or the transaction had been undertaken at an earlier date selected for purposes of the illustration. Accordingly, we do not provide any assurance that the actual outcome of the transaction, if the transaction had taken place at 31 December 2015 and at 1 January 2015, would have been as presented.

A reasonable assurance engagement to report on whether the pro forma financial information has been compiled on the basis of the applicable criteria involves performing procedures to assess whether the applicable criteria used by management of the Company in the compilation of the pro forma financial information provide a reasonable basis for presenting the significant effects directly attributable to the event or transaction, and to obtain sufficient appropriate evidence about whether:

- The related pro forma adjustments give appropriate effect to those criteria;
- The pro forma financial information reflects the proper application of those adjustments to the unadjusted financial information; and
- The pro forma financial information has been complied on a basis consistent with the accounting policies of the Company.

The procedures selected depend on the practitioner's judgment, having regard to the practitioner's understanding of the nature of the company, the event or transaction in respect of which the pro forma financial information has been compiled, and other relevant engagement circumstances.

The engagement also involves evaluating the overall presentation of the pro forma financial information.

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

Opinion

In our opinion:

a) the pro forma financial information has been compiled on the basis stated in section 9 of the Information Memorandum; and
b) the basis is consistent with the accounting policies of the Company.

This report has been prepared solely in connection with the filing of the Company's Information Memorandum required by Oslo Stock Exchange's Continuing Obligations of Stock Exchange Listed Companies section 3.5. This report is not appropriate for any other jurisdiction or purpose other than for the transaction described in the Information Memorandum.

KPMG AS
Oslo, 8 September 2016

Mona I. Larsen

Mona Irene Larsen

State Authorised Public Accountant (Norway)

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APPENDIX B—EXPERT OPINION

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

This is a digital representation of a DeGolyer and MacNaughton report.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

REPORT
as of
JANUARY 1, 2016
on
RESERVES and CONTINGENT RESOURCES
for
CERTAIN PROPERTIES
offshore
NORWAY
for
BP NORGE AS

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DEGOLYER AND MACNAUGHTON
5001 SPRING VALLEY ROAD
SUITE 800 EAST
DALLAS, TEXAS 75244

REPORT
as of
JANUARY 1, 2016
on
RESERVES and CONTINGENT RESOURCES
for
CERTAIN PROPERTIES
offshore
NORWAY
for
BP NORGE AS

FOREWORD

Scope of Investigation

This report presents estimates, as of January 1, 2016, of the extent of the proved and probable oil, condensate, natural gas liquids (NGL), and marketable gas reserves and contingent resources of certain properties offshore Norway (Figure 1). BP Norge AS, a wholly owned subsidiary of BP Limited, has requested that this report include evaluations of the Hod, Skarv/Idun, Snadd, Tambar, Tambar East, Ula, and Valhall fields offshore Norway (Table 1). For reporting purposes, BP Norge AS has also requested that oil and condensate reserves and contingent resources be estimated separately and be presented herein as a summed quantity.

Estimates of proved and probable reserves and contingent resources presented in this report have been prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. The reserves definitions are discussed in detail in the Definition of Reserves section of this report, and the contingent resources definitions are discussed in detail in the Definition of Contingent Resources section of this report.

Reserves estimated in this report are expressed as gross and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2015. Net reserves are defined as that portion of the gross reserves attributable to the interests evaluated herein after deducting interests held by others.

The contingent resources in this report are expressed as gross and net contingent resources. Gross contingent resources are defined as the total estimated petroleum that is potentially recoverable from known accumulations after December 31, 2015. Net contingent resources are defined as that portion of the gross contingent resources attributable to the interests evaluated herein after deducting interests held by others.

The contingent resources estimated herein are those quantities of petroleum that are potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable. Because of the uncertainty of commerciality, the contingent resources estimated herein cannot be classified as reserves. The contingent resources estimates in this report are provided as a means of comparison to other contingent resources and do not provide a means of direct comparison to reserves. The contingent resources estimated in this report have an economic status of Undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the ultimate chance of commerciality.

Contingent resources quantities should not be confused with those quantities that are associated with reserves due to the additional risks involved. The quantities that might actually be recovered, should they be developed, may differ significantly from the estimates presented herein. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated.

Estimates of oil, condensate, NGL, and marketable gas reserves and contingent resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates of reserves and contingent resources based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Authority

This report was prepared at the request of Mr. David MacDonald, VP Segment Reserves, BP Limited.

Source of Information

Information used in the preparation of this report was obtained from BP Norge AS. In the preparation of this report we have relied, without independent verification, upon such information furnished by BP Norge AS with respect to property interests, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination of the properties was not considered necessary for the purposes of this report.

DEFINITION of RESERVES

Estimates of proved and probable reserves presented in this report have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. Only proved and probable reserves have been evaluated for this report. The petroleum reserves are defined as follows:

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. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

> *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. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90-percent probability that the quantities actually recovered will equal or exceed the estimate.
>
> *Unproved Reserves* – Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves and Possible Reserves.
>
>> *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. It is

equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves – Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible Reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Reserves Status Categories – Reserves status categories define the development and producing status of wells and reservoirs.

Developed Reserves – Developed Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

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 started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves – Undeveloped Reserves are quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

The extent to which probable and possible reserves ultimately may be recategorized as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Estimates of probable reserves in this report have not been adjusted in consideration of these additional risks to make them comparable to estimates of proved reserves. No possible reserves have been evaluated for this report.

ESTIMATION of RESERVES

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by BP Norge AS, and the analyses of areas offsetting existing wells with test or production data, reserves were categorized as proved or probable.

Where applicable, the volumetric method was used to estimate the original quantities of petroleum in place. Estimates were made by using various types of logs, core analyses, and other available data. Formation tops, gross thickness, and representative values for net pay thickness, porosity, and interstitial fluid saturations were used to prepare structural maps to delineate each reservoir, and isopachous maps were constructed to estimate reservoir volume.

As appropriate, estimates of ultimate recovery were obtained by applying recovery factors to quantities of original petroleum in place. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production history. For cases where history-matched dynamic models were available and applicable, model results were used to estimate recovery factors and future production rates.

For depletion-type reservoirs whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In analyzing decline curves, reserves were estimated only to the limits of economic production.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

The reserves estimates presented herein were generally based on consideration of monthly production data through December 2015. In some instances, certain production and other data after December 31, 2015, through June 10, 2016, were made available by BP Norge AS for review. These data were used to prepare the estimates for this report. Where applicable, estimated cumulative production, as of December 31, 2015, was deducted from the gross ultimate recovery to determine the estimated gross reserves.

Gas quantities estimated herein are marketable gas and sales gas, expressed at a pressure base of 14.7 pounds per square inch absolute (psia) and a temperature base of 60 degrees Fahrenheit (°F) and are reported in millions of cubic feet (10^6ft^3). Marketable gas reserves are defined as the total gas produced from the reservoir after reduction for injection, shrinkage resulting from field separation, processing, flare, and other losses but before reduction for gas consumed in operations (fuel). Sales gas quantities are defined as the marketable gas to be delivered into a gas pipeline for sale after reduction for fuel gas. Marketable gas reserves reported herein include fuel gas as reserves.

Oil, condensate, and NGL reserves reported herein are to be recovered by normal field separation and plant processing. The estimates of oil, condensate, and NGL are reported in thousands of barrels (10^3bbl), where 1 barrel equals 42 United States gallons.

BP Norge AS has represented that it holds interests in the properties evaluated in this report as follows:

Field	Working Interest (Percent)	License Expiration
Hod	37.500	12/31/2020
Skarv/Idun	23.835	2/2/2033
Snadd	23.835	2/2/2033
Tambar	55.000	1/1/2022
Tambar East	46.200	1/1/2022
Ula	80.000	1/1/2029
Valhall	35.953	12/31/2028

In certain instances, reserves for the fields have been estimated beyond the terms of the license limit based on the representation by BP Norge AS that it will apply for and be granted license extensions until an economic limit has been reached.

The Skarv/Idun and Snadd fields are located southwest of the Norne field in the northern part of the Norwegian Sea. The fields were discovered by the exploration wells (in three structures) 6507/5-1 (Skarv), 6507/3-3 (Idun), and 6507/5-3 (Snadd), which have been unitized. Structurally, the Skarv and Idun structures consist of a set of Jurassic blocks situated between the Trondelag Platform to the east and the Ras Basin to the west. For the purposes of this report, the Skarv and Idun structures (Figure 2) are treated collectively, while Snadd (being in a separated parallel trend) is treated separately. The geometry of the Skarv/Idun field is dominated by the main fault to the east and a local detachment in the hanging wall, which is relatively deep and shallows toward the Idun structure. Parallel faulting is observed with more complex oblique faulting located toward the south and west of the Skarv/Idun field.

The main reservoir in the Skarv/Idun field is the Jurassic Garn Formation. The Jurassic Ile and Tilje Formations are also present and contribute to production. In the Skarv B and C structure areas, the reservoirs are gas-filled at the crest, underlain with an oil leg located in the south. The Idun and Skarv A Garn structure areas are also gas reservoirs. The gas reservoirs have associated condensate production, which is blended with the oil. The rich gas from the Skarv/Idun field is processed at Karsto and produces NGL. Production from the Skarv/Idun field began in 2012 to a floating, production, storage, and offloading vessel tied to five subsea templates. In the Garn and Tilje Formations, gas is reinjected to maintain pressure to support oil recovery. The oil and condensate are buoy-loaded to tankers, while the gas is exported via pipeline connected to the Åsgard Transport system. Proved developed reserves for the Skarv/Idun field were estimated based on volumetric calculations supported by performance from existing wells. Recovery factors for the proved developed oil reserves ranged from 45 to 55 percent, with the lower recovery associated with the Tilje reservoir and the higher recovery associated with the Garn reservoir. The proved developed recovery factor for the gas reservoirs was estimated to be 70 percent. Probable reserves were estimated for better performance recovery than proved reserves from the existing wells.

The Snadd field is located southwest and northeast of, and parallel to, the Skarv/Idun field. Createcous reservoirs exist in the Snadd field, the largest and most prolific of which is the Lysing sandstone (Snadd gas discovery), which has minimal variation in structure but covers a large areal extent. The Snadd test well, A-1H, came on production in 2013 and produces for long-term testing purposes, which is anticipated to continue through 2017. Development of the Snadd field is planned in three stages, as represented by the operator: Phase 0, Phase 1, and Phase 2. Phase 0 consists of production from the existing well A-1H, beginning in 2017. For Phase 1, development includes three new wells in the southern part of the field tied to the Skarv/Idun A template, with first gas occurring in 2020. An additional three new wells in the northern part of the field tied to the Idun template are planned for Phase 2 development, with first production occurring in 2024. All plans being considered for the final Plan for Development and Operation (PDO) include at least three new wells, as represented by BP Norge AS. The final PDO will be submitted in 2017. Based on the representation by BP Norge AS that the PDO has been agreed upon between the field partners, reserves for the Snadd field have been estimated in this report. Reserves were estimated based on volumetric calculations. The proved reserves were estimated by utilizing a gas recovery factor of 70 percent, which is based on analogy to the performance of gas reservoirs in the Skarv/Idun field. Probable reserves were estimated for better recovery than for proved reserves.

The Tambar and Tambar East fields are located offshore Norway in Blocks 1/3 and 2/1, in the southern portion of the Norwegian North Sea. The Tambar field is in Production License (PL) 065. The Tambar East field is in PL300. The Tambar/Tambar East structure is an elongate, faulted closure trending northwest to southeast. The Tambar and Tambar East fields are separated by a major northwest/southeast-trending fault complex. The productive reservoir is the Jurassic. The Tambar field began producing in mid-2001 as a tieback to the Ula field, and the Tambar East field began production in September 2007. Proved developed reserves for both field areas were estimated based on field performance of currently producing wells on natural depletion, and proved undeveloped reserves were estimated for the planned addition of gas lift to several producers, as well as one additional committed infill well. Probable reserves were estimated based on performance interpretations superior to the performance estimates for proved reserves.

The Ula field is a mature field north of the Tambar field that began production in 1986 from Jurassic sandstone in

Block 7/12. The field's reported OOIP was just over 1 billion barrels, of which nearly half has already been produced. Ula field facilities process liquids and sales gas for the Tambar and Tambar East fields. Water injection capacity was upgraded in 2006, and an ongoing water-alternating-gas (WAG) project has contributed to increasing oil rates. Proved developed reserves were estimated based on performance projections for the current wells and facilities, including water and gas injection. Proved undeveloped reserves were estimated for anticipated WAG injection increases from increased gas supply from the Tambar Artificial Lift project and the Tambar Infill South well. Probable reserves have been estimated for better performance, enhanced injection, and continuation of the WAG project. Probable reserves were estimated using analogy and water-oil ratio analysis to capture the additional recovery from increased water and WAG injection efficiency, including gas supply from the nearby Butch field, coupled with dynamic simulation.

The Valhall field is a large, maturing oil field located in the Norwegian North Sea on Blocks 2/8 and 2/11, in approximately 70 meters of water. The field was discovered in 1975 and began producing in 1982. It produces from the Tor and Hod Formations (Figure 3), and approximately 90 wells have been drilled to date in the Valhall field.

The Valhall field was originally developed with three platform facilities (QP, DP, and PCP) for accommodation, drilling, and processing. The Valhall wellhead facility (WP) was installed in 1996 and the injection platform (IP) was installed in 2003. The Valhall flank development included an additional platform in the south (VFD South) in 2003 and the north (VFD North) in 2004. An accommodation and processing platform (PH) was added in 2012 to replace aging facilities in the field.

The Upper Cretaceous Tor Chalk Formation is fine grained and soft. Due to the chalk composition, the Valhall field is subject to subsidence. Cumulatively, the seabed has subsided approximately 6.5 meters. The reservoir depth is approximately 2,400 meters subsea, and the reservoirs have generally high porosity. The field was initially produced by pressure depletion before central field water injection (heretofore poorly implemented) was started in 2004. Gas lift was added in 2015 to optimize production.

The Hod field is located approximately 13 kilometers southwest of the Valhall field. It was discovered in 1974 and began producing in 1990 from a normally unmanned platform with tie-backs to Valhall.

The Hod field currently produces through the Valhall facility from four wells drilled from the Valhall South Flank platform. All wells drilled from the Hod platform are currently shut in waiting to be plugged and abandoned.

Reserves estimates for the Valhall and Hod fields were based on performance evaluation. Proved developed reserves were based on performance analysis of the producing wells existing on January 1, 2016. Proved undeveloped reserves in Valhall were estimated for seven new infill wells to be drilled from the IP commencing 2017 and two water injectors to be drilled in the North Flank in 2019. Undeveloped reserves were estimated based on type curves derived from historical analysis of previous drilling programs. Probable undeveloped reserves in Valhall were estimated for six wells to be drilled in the West Flank of the field, commencing in 2020. Probable developed reserves for both fields were estimated based on better well performance than projected for proved reserves.

The estimated gross and net proved and probable oil and condensate, NGL, and marketable gas reserves attributable to BP Norge AS in the fields offshore Norway evaluated herein, as of January 1, 2016, are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

	Gross Reserves		
	Oil and Condensate (10^3bbl)	**NGL (10^3bbl)**	**Marketable Gas (10^6ft^3)**
Proved			
Developed	253,353	42,751	1,051,326
Undeveloped	92,877	24,607	715,291
Total Proved	**346,230**	**67,358**	**1,766,617**
Probable	109,513	18,064	357,187

	Net Reserves		
	Oil and Condensate (10^3bbl)	**NGL (10^3bbl)**	**Marketable Gas (10^6ft^3)**
Proved			
Developed	100,589	13,641	286,720
Undeveloped	32,940	6,816	179,402
Total Proved	**133,529**	**20,457**	**466,122**
Probable	45,335	6,031	97,455

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

The reserves estimated herein are based on economic analyses that utilize the following Base Scenario future product prices in United States dollars per barrel (U.S.$/bbl), United States dollars per metric ton (U.S.$/mt), or United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3) as provided by BP Norge AS:

	Base Scenario		
Year	Oil and Condensate (U.S.$/bbl)	NGL (U.S.$/mt)	Sales Gas (U.S.$/$10^3$ft^3)
2016	60.00	533.33	7.17
2017	61.50	546.67	7.35
2018	63.04	560.33	7.54
2019	64.61	574.34	7.73
2020	66.23	588.70	7.92
2021	67.88	603.42	8.12
2022	69.58	618.50	8.32
2023	71.32	633.97	8.53
2024	73.10	649.81	8.74
2025	2.5 percent increase per year for all products		

Note: The Skarv/Idun and Snadd fields receive a 5.5-percent price premium to the sales gas prices above, based on the energy content of the gas.

All reserves reported herein have been estimated based on the Base Scenario. However, BP Norge AS requested that this report also contain three alternative price scenarios: Low, High, and BP Planning. The Low and High Scenarios represent a constant U.S.$10.00 per barrel offset to the Base Scenario, while NGL and sales gas prices are not modified from the Base Scenario. For the BP Planning Scenario, the starting point is U.S.$80.00 per barrel in 2015, coupled with separate NGL and sales gas prices provided by BP Norge AS. In all alternative price scenarios, economic quantities were permitted to extend beyond the economic limit of the Base Scenario reserves cases. No individual field price offsets were used except where footnoted. All other components of the evaluation, including costs, for the sensitivity cases are the same as stated for the Base Scenario.

	Low Scenario		
Year	Oil and Condensate (U.S.$/bbl)	NGL (U.S.$/mt)	Sales Gas (U.S.$/$10^3$ft^3)
2016	50.00	533.33	7.17
2017	51.25	546.67	7.35
2018	52.53	560.33	7.54
2019	53.84	574.34	7.73
2020	55.19	588.70	7.92
2021	56.57	603.42	8.12
2022	57.98	618.50	8.32
2023	59.43	633.97	8.53
2024	60.92	649.81	8.74
2025	2.5 percent increase per year for all products		

Note: The Skarv/Idun and Snadd fields receive a 5.5-percent price premium to the sales gas prices above, based on the energy content of the gas.

Year	High Scenario Oil and Condensate (U.S.$/bbl)	NGL (U.S.$/mt)	Sales Gas (U.S.$/$10^3$ft^3)
2016	70.00	533.33	7.17
2017	71.75	546.67	7.35
2018	73.54	560.33	7.54
2019	75.38	574.34	7.73
2020	77.27	588.70	7.92
2021	79.20	603.42	8.12
2022	81.18	618.50	8.32
2023	83.21	633.97	8.53
2024	85.29	649.81	8.74
2025	2.5 percent increase per year for all products		

Note: The Skarv/Idun and Snadd fields receive a 5.5-percent price premium to the sales gas prices above, based on the energy content of the gas.

Year	BP Planning Scenario Oil and Condensate (U.S.$/bbl)	NGL (U.S.$/mt)	Sales Gas (U.S.$/$10^3$ft^3)
2016	82.00	664.61	10.98
2017	84.05	681.23	11.25
2018	86.15	698.26	11.53
2019	88.31	715.72	11.82
2020	90.51	733.61	12.12
2021	92.78	751.95	12.42
2022	95.09	770.75	12.73
2023	97.47	790.02	13.05
2024	99.91	809.77	13.38
2025	2.5 percent increase per year for all products		

Note: The Skarv/Idun and Snadd fields receive a 5.5-percent price premium to the sales gas prices above, based on the energy content of the gas.

NGL volumes have been converted to metric tons (mt) for sales purposes using the specific gravities shown below:

Field	NGL Specific Gravity
Hod	0.526
Skarv/Idun	0.510
Snadd	0.510
Tambar	0.526
Tambar East	0.526
Ula	0.526
Valhall	0.526

For all scenarios, historical and current costs have been provided by BP Norge AS. Estimates herein are based on a specific projection of costs provided by BP Norge AS. These projections were modified to represent the activities included in each production forecast scenario. License costs are considered along with tariffs herein to determine economic limit and reserves. Capital costs are those associated with development in each field as described herein, and those costs include drilling and facility components where applicable. Where necessary, costs provided in United States dollars (U.S.$) were converted to Norwegian Kroner (NOK) using the conversions shown below:

Year	(NOK/U.S.$)
2015	8.07
2016	8.52
2017	8.30
2018	7.90
2019	7.40
2020	7.20
2021	7.10
2022	7.00
2023	6.90
2024	6.90
2025	6.90
2026 Forward	7.00 thereafter

All costs are inflated at 2.5 percent per year after currency conversion.

Table 2 summarizes the reserves estimated in this report. Reserves estimated herein are those representing the Base Scenario only. Gross proved and probable oil, condensate, and NGL reserves are presented by field in Table 4 for the Base Scenario. Tables 5 through 7 present the oil, condensate, and NGL quantities associated with the Low, High, and BP Planning Scenarios, respectively. Gross proved and probable gas reserves are presented by field in Table 8 for the Base Scenario. Tables 9 through 11 present the associated gas quantities for the Low, High, and BP Planning Scenarios, respectively. Tables 12 and 13 show the net reserves (established under the Base Scenario) attributable to the interests of BP Norge AS evaluated herein.

Tables 16 and 17 are projection summaries for all fields of the estimated future production and costs for the gross proved and proved-plus-probable reserves, respectively, while Tables 18 through 31 include projections of gross proved and proved-plus-probable reserves and cost estimates by field.

DEFINITION of CONTINGENT RESOURCES

Petroleum resources included in this report are classified as contingent resources and have been prepared in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. Because of the lack of commerciality or sufficient development drilling, the contingent resources estimated herein cannot be classified as reserves. The petroleum resources are classified as follows:

> *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.
>
> Based on assumptions regarding future conditions and their impact on ultimate economic viability, projects currently classified as Contingent Resources may be broadly divided into three economic status groups:
>
>> *Marginal Contingent Resources* – Those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.
>>
>> *Sub-Marginal Contingent Resources* – Those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonably forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.
>>
>> *Undetermined Contingent Resources* – Where evaluations are incomplete such that it is premature to clearly define ultimate

chance of commerciality, it is acceptable to note that project economic status is "undetermined."

The estimation of resources quantities for an accumulation is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable volumes. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

1C (Low), 2C (Best), and 3C (High) Estimates – Estimates of petroleum resources in this report are expressed using the terms 1C (low) estimate, 2C (best) estimate, and 3C (high) estimate to reflect the range of uncertainty.

ESTIMATION of CONTINGENT RESOURCES

Estimates of contingent resources were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Where applicable, the volumetric method was used to estimate the original quantities of petroleum in place. Estimates were made by using various types of logs, core analyses, and other available data. Formation tops, gross thickness, and representative values for net pay thickness, porosity, and interstitial fluid saturations were used to prepare structural maps to delineate each reservoir, and isopachous maps were constructed to estimate reservoir volume.

As appropriate, estimates of ultimate recovery were obtained by applying recovery factors to quantities of original petroleum in place. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, and the structural positions of the properties.

In certain cases, contingent resources were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

At the request of BP Norge AS, data available through June 10, 2016 on the properties were used to prepare the estimates of contingent resources herein. The development and economic status represents the status applicable on January 1, 2016.

Gas quantities estimated herein are marketable gas and sales gas, expressed at a pressure base of 14.7 pounds per square inch absolute psia and a temperature base of 60 °F and are reported in $10^6 ft^3$. Marketable gas contingent resources are defined as the total gas produced from the reservoir after reduction for injection, shrinkage resulting from field separation, processing, flare, and other losses but before reduction for gas consumed in operations (fuel), where discernible. Sales gas contingent resources are defined as the marketable gas to be delivered into a gas pipeline for sale after reduction for fuel gas. Marketable gas contingent resources reported herein include fuel gas as contingent resources.

Oil, condensate, and NGL contingent resources reported herein are to be recovered by normal field separation and plant processing. The estimates of oil, condensate, and NGL are reported in 10^3bbl, where 1 barrel equals 42 United States gallons.

The contingent resources estimated herein are those quantities of petroleum that are potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable. Because of the uncertainty of commerciality, the contingent resources estimated herein cannot be classified as reserves. The contingent resources estimates in this report are provided as a means of comparison to other contingent resources and do not provide a means of direct comparison to reserves. At the request of BP Norge AS, all contingent resources have an economic status of Undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the ultimate chance of commerciality.

Generally, contingent resources estimated herein are based on future projects that have not yet been approved by the operator or lack the commitment to develop.

Contingent resources associated with the Tambar field are attributed to the drilling of one northern infill well, which will have artificial gas lift installed. The well would be drilled and on production by the end of 2018.

For the Skarv/Idun field, contingent resources were estimated for the Grasel structure, above the Skarv structure. The Cretaceous Grasel structure was discovered in well 6507/5-1 during drilling of the Skarv Jurassic zones. The primary reservoir of interest in the Grasel structure is the Lange reservoir, which was determined to contain both oil and gas. Development of the Grasel has been postponed until further optimization studies can be performed. Additional contingent resources were estimated in the Skarv/Idun field for small sections of the Tilje and Garn oil reservoirs located in the southern part of the field, which were interpreted not to be in communication with any of the existing wells.

All of the contingent resources in the Skarv/Idun field were estimated volumetrically.

For the Ula field, contingent resources were estimated for increased WAG efficiency through improved gas supply from an additional Tambar infill well and an additional WAG producer/injector pair, as well as future development of the Ula North field and further development of the Triassic reservoir. These include gas-producing projects in the Tambar and Tambar East fields.

Contingent resources in the Valhall and Hod fields were based on future projects that are at various stages of approval and have not reached the point of a final investment commitment. For the Valhall field, the contingent resources include quantities associated with drilling infill wells on the South Flank, developing the Lower Hod Formation, and additional infill drilling from IP/WP platforms. For the South Flank project, the 1C and 2C contingent resources were based on drilling two new producers in 2020. The Lower Hod Formation project includes drilling/re-drilling seven producers and four injectors. The 1C contingent resources include two producers and two injectors drilled from 2021 through 2023. The 2C contingent resources include seven producers and four injectors drilled from 2021 through 2025. The IP/WP infill drilling project includes drilling/re-drilling eight producers and two water injectors. The 1C contingent resources include two producers and one injector drilled from 2026 through 2027. The 2C contingent resources include eight producers and two injectors drilled from 2026 through 2029.

The Hod field contingent resources include quantities associated with the Hod Redevelopment project and the Hod East waterflood project. The Hod Redevelopment project includes the installation of a new platform and six new producers drilled from 2024 through 2026. The 1C contingent resources include two producers and the 2C contingent resources include six producers. The Hod East project includes drilling four producers from 2025 through 2028. The 1C contingent resources include one producer and the 2C contingent resources include four producers.

The estimated gross and net oil and condensate, NGL, and marketable gas contingent resources attributable to BP Norge AS in the fields offshore Norway evaluated herein, as of January 1, 2016, are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

	Gross Contingent Resources		
	Oil and Condensate (10^3bbl)	**NGL (10^3bbl)**	**Marketable Gas (10^6ft^3)**
1C	82,012	9,232	71,861
2C	221,525	25,786	199,087

	Net Contingent Resources		
	Oil and Condensate (10^3bbl)	**NGL (10^3bbl)**	**Marketable Gas (10^6ft^3)**
1C	34,830	3,353	25,057
2C	92,408	9,429	70,379

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. At the request of BP Norge AS, the contingent resources estimated in this report have an economic status of Undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the ultimate chance of commerciality.

Estimates of contingent resources are summarized in Table 3. The gross and net 1C and 2C oil and condensate, NGL, and marketable gas contingent resources expressed in 10^3bbl and 10^6ft^3 are presented by field in Tables 14 and 15.

SUMMARY and CONCLUSIONS

BP Norge AS has represented that it holds interests in the Hod, Skarv/Idun, Snadd, Tambar, Tambar East, Ula, and Valhall fields offshore Norway, which are evaluated herein.

The estimated gross and net proved and probable oil and condensate, NGL, and marketable gas reserves attributable to BP Norge AS in the fields offshore Norway evaluated herein, as of January 1, 2016, are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

	Gross Reserves		
	Oil and Condensate (10^3bbl)	NGL (10^3bbl)	Marketable Gas (10^6ft^3)
Proved			
Developed	253,353	42,751	1,051,326
Undeveloped	92,877	24,607	715,291
Total Proved	**346,230**	**67,358**	**1,766,617**
Probable	109,513	18,064	357,187

	Net Reserves		
	Oil and Condensate (10^3bbl)	NGL (10^3bbl)	Marketable Gas (10^6ft^3)
Proved			
Developed	100,589	13,641	286,720
Undeveloped	32,940	6,816	179,402
Total Proved	**133,529**	**20,457**	**466,122**
Probable	45,335	6,031	97,455

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

The estimated gross and net oil and condensate, NGL, and marketable gas contingent resources attributable to BP Norge AS in the fields offshore Norway evaluated herein, as of January 1, 2016, are summarized as follows, expressed in thousands of barrels (10^3bbl) and millions of cubic feet (10^6ft^3):

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	Net Contingent Resources		
	Oil and Condensate (10^3bbl)	NGL (10^3bbl)	Marketable Gas (10^6ft^3)
1C	34,830	3,353	25,057
2C	92,408	9,429	70,379

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. At the request of BP Norge AS, the contingent resources estimated in this report have an economic status of Undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the ultimate chance of commerciality.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

SIGNED: August 8, 2016

Lloyd W. Cade, P.E.

Lloyd W. Cade, P.E.
Senior Vice President
DeGolyer and MacNaughton

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APPENDIX C—ANNUAL ACCOUNTS OF BP NORGE AS

BP NORGE AS

Annual Accounts 2015

BP NORGE AS

INCOME STATEMENT

NOK 1 000	Notes	2015	2014
Operating income			
Petroleum income	2	7 899 328	12 377 232
Other income	3	35 321	91 730
Total operating income		7 934 649	12 468 962
Operating expenses			
Change in over-/under lifting of petroleum		-46 724	216 193
Transport expenses		621 963	670 485
Payroll expenses	4, 9	885 453	802 458
Depreciation and depletion	6	3 107 633	3 194 905
Impairment	6	0	7 107 357
Production costs		2 037 468	2 005 072
Other operating expenses	4, 16	759 679	894 248
Removal and abandonment		1 392 401	2 482 225
Total operating expenses		8 757 873	17 372 944
Operating profit		**-823 224**	**-4 903 981**
Financial income and expenses			
Interest received from group companies		17 601	18 522
Other interest income		2 327	3 620
Interest paid to group companies		-344 141	-495 692
Other interest expenses		-6 638	-7 654
Net foreign currency losses/gain		270 144	336 695
Net financial items		-60 708	-144 508
Ordinary profit before tax		**-883 933**	**-5 048 489**
Taxes	5	-583 306	-583 306
Profit for the year		**-300 627**	**-4 465 184**
Allocated to dividend		0	0

BALANCE SHEET AS AT 31 DECEMBER

NOK 1 000	Notes	2015	2014
Assets			
Fixed assets			
Intangible assets			
Mineral rights	6	909 904	909 904
Long-term operating assets			
Production plant and pipeline	6	19 821 845	22 204 418
Capitalised exploration and evaluation expenses	6	132 672	109 330
Means of transport, machinery and fixtures	6	62 462	70 105
Total fixed assets		20 926 883	23 293 757
Current assets			
Stocks	16	271 699	329 076
Receivables			
Accounts receivable from customers		69 070	5 597
Accounts receivable from group companies	7	2 162 444	2 380 220
Other receivables		23 010	392 333
Under lifting of petroleum		70 544	75 916
Bank deposits	7	13 195	2 143
Total current assets		2 609 962	3 185 286
Total assets		23 536 845	26 479 043

BP NORGE AS

BALANCE SHEET AS AT 31 DECEMBER

NOK 1 000	**Notes**	**2015**	**2014**
Equity and liabilities			
Equity			
Contributed equity			
Share capital	8	2 000	2 000
Share premium	8	2 874 000	2 874 000
Earned equity			
Other equity	8	828 048	1 128 675
Total equity		3 704 048	4 004 675
Liabilities			
Provisions for obligations			
Pension obligations	9	657 428	452 211
Deferred taxation	5	2 443 627	3 058 864
Provisions for removal and abandonment	11	7 529 252	6 947 890
Total provisions for obligations		10 630 307	10 458 965
Other long-term liabilities			
Debt to group companies	10	7 500 000	10 000 000
Total other long-term liabilities		7 500 000	10 000 000
Short-term liabilities			
Public duties payable		116 790	115 487
Tax payable	5	162 705	180 914
Debt to group companies		55 282	70 166
Other short-term liabilities	12	1 281 431	1 510 458
Over lifting of petroleum		86 282	138 377
Total short-term liabilities		1 702 490	2 015 403
Total equity and liabilities		23 536 845	26 479 043

Board of Directors, BP Norge AS
Stavanger, 31. March 2016

Peter J. Mather
(Chairman)

Jan J. Norheim　　Christen I. Minos　　Mark J. Thomas

Kåre Ekroll　　Ørjan Holstad　　Christine Eikeberg　　Ingard Haugeberg

BP NORGE AS

CASH FLOW STATEMENT

NOK 1 000	**2015**	**2014**
Cash flow from operating activities		
Ordinary profit before taxes	-883 933	-5 048 489
Taxes paid during the period	-50 140	18 571
Depreciation, depletion and impairment	3 107 633	10 302 262
Removal and abandonment expenses	1 392 401	2 482 225
Change in short-term receivables and stocks	586 377	-859 346
Change in short-term liabilities	-294 703	-711 818
Change in other accrual items	205 216	123 626
Actual decommissioning costs	-811 041	-609 960
Net cash flow from operating activities	**3 251 810**	**5 697 071**
Cash flow to investment activities		
Disbursements for acquisitions of fixed assets	-740 759	-1 905 429
Net cash flow to investment activities	**-740 759**	**-1 905 429**
Cash flow to financing activities		
Repayment of long-term debt	-2 500 000	-3 800 000
Net cash flow to financing activities	**-2 500 000**	**-3 800 000**
Net change in cash and cash equivalents for the period	**11 052**	**-8 357**
Cash and cash equivalents, 1 January	**2 143**	**10 500**
Cash and cash equivalents, 31 December	**13 195**	**2 143**

ACCOUNTING PRINCIPLES

General
The annual accounts of BP Norge AS have been prepared in accordance with Norwegian law, regulations for preparing annual accounts, and the generally accepted accounting principles in Norway.

Sales revenue
The sales of crude oil, gas and NGL are recognized at the delivery point, based on the terms and conditions in the sales agreement. Revenues from the production of oil and natural gas properties in which the company has an interest with joint operation partners are recognized based on the sales method.
Other revenue is recorded at the time of the delivery.

Over- and under lifting of petroleum
Over- and under lifting of petroleum in relation to the company's interest in petroleum lifted from a field, is valued in accordance with the sales method. If the sales value is lower than the production value, any under lifting is valued at the sales price. The over- and under lift will be classified as receivables and short term liabillities.

Exploration expenses/field development
Exploration expenses are capitalized in accordance with the "successful" effort method. All expenses related to field development are capitalized.

Intangible assets
Intangible assets are carried at the lower of cost and recoverable amount. Intangible assets include the cost for exploration rights.

Depreciation
Depreciation of investments on the continental shelf are calculated in accordance with the unit of production method. Proved reserves are used. Tangible fixed assets onshore are depreciated with the declining balance method, except the costs related to reconstructions in the office building. These costs are depreciated linearly in accordance with the lease contract.

Impairment
Assets are assessed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows. An asset group's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. If any indication that previously recognized impairment losses no longer exist, except for goodwill, impairment loss is reversed.

Stocks
Spare parts are recognized on inventories at cost. Stocks of petroleum that have not exceeded the norm price are valued at nil.
Gas in pipelines are not recognized as stocks.

Removal/abandonment of wells
The company makes provisions for the removal and abandonment of wells. Provisions for the current year are calculated in accordance with the unit of production method, based on net present value calculations. The total estimate for the company's share will be charged against income in the years prior to abandonment based on the production for the individual year.
When estimates are revised, the effect is recognized in the income statement in the period in which the estimate is revised.

Research and development
R&D costs are charged against income on a current basis.

Foreign currency
Income, expenses and the addition of fixed assets are accounted for at the daily accounting rate.
Receivables and liabilities are converted at rate as at 31 of December

Tax charge and deferred taxes on the balance sheet
The profit and loss statement indicates the amount of the tax charge, which expresses the tax charge related to the financial result.
Deferred taxes on the balance sheet is the tax calculated on net positive temporary differences between the financial and tax-related balance sheet values after the negative temporary differences have been offset. Full provisions are made in accordance with the debt method. The calculation of deferred taxes shall take into account future tax-reducing items such as unutilized uplift.
Deferred taxes have not been calculated on capitalized assets in connection with purchases where the compensation is an after-tax transaction.

ACCOUNTING PRINCIPLES

Pensions
The company has pension plans that entitle employees on the Norwegian payroll to future pension benefits (benefit scheme). The net pension payment and calculated pension obligations are calculated in accordance with the Norwegian Accounting Standard. Actuarial gain/loss is amortized over remaining

Joint licenses
The company's share in joint licenses has been included under the respective items in the profit and loss statement and balance sheet.

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 placement with original maturities of three months or less.

Leasing commitments
Leasing agreements without transfer of material risk and control to the leaser are considered as operating leasing. The Company's leasing expences in operating leases are reflected as current operating costs.

NOTES TO THE ACCOUNTS

Note 1. The company

In 2015 the company has had production from Valhall (ownership interest 35.95%), Ula (ownership interest 80,00%), Hod (ownership interest 37.50%), Tambar (ownership interest 55,00%), Tambar East (ownership interest 46,20%) and Skarv (ownership interest 23.835%). BP is the operator on these fields.

Note 2. Petroleum income

	Crude oil		Wet gas		Gas		Total
	NOK 1 000	Thousand bbls	NOK 1 000	Thousand bbls	NOK 1 000	Thousand SM3	NOK 1 000
Ula	920 053	2 133	6 550	47	0	0	926 603
Tambar*	374 164	884	10 789	54	6 715	5 545	391 668
Skarv	1 950 038	4 527	256 465	1 201	1 736 306	907 802	3 942 809
Valhall	2 145 652	5 274	49 202	262	380 818	164 477	2 575 672
Hod	65 527	165	1 251	6	1 169	673	67 949
Elimination**					-5 372	-4 436	-5 372
Sum	5 455 434	12 983	324 257	1 570	2 119 637	1 074 062	7 899 328

* Includes Tambar East

**Elimination applies to gas that the Tambar field sells to the Ula field for injection.

Note 3. Other Income

NOK 1 000	2015	2014
Freight and tariffs	33 795	54 556
Revenue regarding disposed assets	0	35 661
Other income	1 526	1 513
Total other income	35 321	91 730

Note 4. Payroll expenses, number of employees, remuneration, loans to employees, etc.

Payroll expenses:

	2015		2014	
in million NOK	Gross	Net	Gross	Net
Payroll expenses	1 374	623	1 331	579
Pension expenses	357	162	286	124
Employer's contribution	221	100	228	99
Total	1 952	885	1 845	802
Average number of employees	857		834	

Gross payroll expenses includes expenses allocated to the partners at the Jonit Ventures.

BP's share savings scheme.

BP has a share savings plan open to all local employees. The scheme allows employees to purchase shares in BP Plc once a year. The investment shares are retained for a period of one year, where after the participants will receive a matching number of shares from the company. 50% of the additional shares will be released upon receipt, while the rest are being held in deposit for two years before being released. Custodian institution is DnB.

Max amount converted into shares for the scheme is in line with other share schemes in the BP group, and is set each year according to BP's Group Performance.

Note 4. cont.

Bonuse scheme in the BP Group

The bonus scheme in the company rewards employees for achievements that help contribute to BP's long-term success. The bonus is the annual incentive for delivering individual priorities and key milestones in the context of business results. Bonus payout will depend on base salary, bonus opportunity at goal attainment, and the group, entity and individual achievement. Bonus achievement will be adjusted up or down based upon the three achievement assessments, to determine the actual payout. Each performance factor are equal to the other.

Loans to employees

Loans to employees amounted to NOK 560 598 pr. 31.12.2015. The loans are included in other receivables in the balance sheet.
There has been given no loans or guarantees for other commitments on behalf of senior personnel, Chairman or shareholders and their families per 31.12.2015

Remuneration to the CEO

Recorded labor costs for the CEO of BP Norway AS, can be specified as follows:

in million NOK	2015	2014
Salary and bonus	3,4	3,2
Other remuneration	0,6	0,6
Total	4,0	3,8

The company's coverage of CEO's pension was NOK 174 518 in 2015.

There are no agreements for payment upon termination or change of employment for the CEO.

The BP Group has implemented a share value based remuneration called " Share Value Plan". This is a global plan used to allocate shares to Group Leaders , Senior Leaders and selected employees of the various companies in BP. The plan will support the strategic priorities of value creation and long-term stewardship of BP Groups business. The grant amount is determined based on a fixed percentage of base pay and has three years vesting period. There are specific conditions linked to the grant, such as performance and continuous employment.

The CEO is included in the schemes mentioned above.

Remuneration to the Board

Expenced remuneration to the board was NOK 80 000 for 2015.

Remuneration of Auditor

Recorded audit fee was NOK 932 286 (excluding VAT) for 2015, of which NOK 42 000 relates to the purchase of other audit related services.

NOTES TO THE ACCOUNTS

Note 5. Tax

Deferred taxes are calculated on the temporary differences between the financial- and tax-related values at the end of the year.

NOK 1 000	2015	2014
Specification of basis for deferred taxes:		
Fixed assets	14 377 443	14 376 503
Provisions for removal and abandonment	-7 446 198	-9 841 971
Other	-983 561	-852 791
Basis for corporate tax	5 947 684	6 681 741
Unutilized uplift	-4 142 578	-4 221 361
Basis for special tax	1 805 106	2 460 380
25% corporate tax	1 486 921	1 804 070
53 % special tax	956 706	1 254 794
Total deferred taxes	2 443 627	3 058 864

Tax payable on the balance sheet:

Tax payable on profit for the year	162 705	129 293
Tax payable previous year	0	51 621
Total tax payable	162 705	180 914

The tax charge for the year is calculated as follows:

Tax payable on profit for the year	31 931	129 293
Correction, previous years	0	48 011
Change, deferred tax	-615 236	-3 587 508
Tax charge	-583 306	-3 410 203

Reconciliation from nominal to actual tax rate:

Pre-tax profit	-883 933	-5 048 489
Marginal tax (78%)	-689 467	-3 937 822
Other permanent differences	107 698	381 711
New uplift	-16 009	-225 595
Financial result onshore and other	-21 119	-1 610
Adjustments for previous years	122 863	373 112
Recognised effect of change in tax rate on deferred tax	-87 272	0
Tax charge	-583 306	-3 410 203

Note 6. Fixed assets and intangible assets

Fixed assets

NOK 1 000	Capitalised exploration and evaluation expenses	Production plant	Machinery/ fixtures/ vehicles	Total fixed assets
Historical cost 01.01.2015	109 330	53 432 923	618 895	54 161 149
Additions 2015	23 342	703 715	13 703	740 759
Transfers 2015	0	0	0	0
Historical cost 31.12.2015	132 672	54 136 638	632 598	54 901 908
Acc. depr. and imp. 31.12.2015	0	34 314 793	570 136	34 884 929
Balance sheet value 31.12.2015	132 672	19 821 845	62 462	20 016 979
Current year depreciation	0	3 086 287	21 346	3 107 633
Current year impairment	0	0	0	0

Intangible assets

NOK 1 000	Mineral rights
Historical cost 01.01.2015	1 106 730
Additions 2015	0
Historical cost 31.12.2015	1 106 730
Acc. depr. and imp. 31.12.2015	196 826
Balance sheet value 31.12.2015	909 904
Current year depreciation	0
Current year impairment	*0*

Total impairment losses in 2014 amounted to NOK 7 107 million, of which NOK 6 911 million related to fixed assets and NOK 197 million related to intangible assets. The impairments were a result of a lower price environment in the near term, technical reserves revisions, and increases in expected decommissioning cost.

Note 7. Bank deposit

Bank deposits per 31.12.2015 are NOK 13,2 million. Balance in corporate banking at NOK 1 296,3 million, has been reclassified to accounts receivable from group companies in the balance sheet for 2015. The banking facility has a limit of NOK 50 million, whereas the corporate banking facility has a limit of 3 000 million.

Note 8. Equity development

NOK 1 000	Share Capital	Share Premium	Other Retained Equity	Total
Equity 1 Jan.	2 000	2 874 000	1 128 675	4 004 675
Profit for the year	-		-300 627	-300 627
Equity 31 Dec.	2 000	2 874 000	828 048	3 704 048

The share capital consists of 1 000 shares with a par value of NOK 2 000. The shareholders are BP Global Investments Ltd. which owns 480 shares and Amoco Norway Oil Company which owns 520 shares. All shares are equal.

Note 9. Pensions

BP has fulfilled most of its pension obligations through payment to a Norwegian life insurance company. The pension plan encompasses 1000 pensioners and employees from the age of 20. The company's retirement age is 65 for offshore employees and 67 for onshore employees.

The actual value of the pension funds and net present value of the pension obligations are as follows at the balance sheet date:

NOK 1 000	2015	2014
Value of pension funds	1 797 446	1 631 370
Net present value of vested pension obligations, incl future salary increases	-2 574 220	-3 189 855
Unamortized loss	232 516	1 331 321
Over funding pension obligation	-544 259	-227 164
Employer's national insurance contributions	-109 525	-219 746
Total over funding pension obligation	-653 784	-446 910

Pension costs

Pension costs for the year are as follows:

Net value of current year's pension benefit earned	238 503	182 195
Interest cost of accrued pension obligation	72 640	96 085
Anticipated return on pension funds	-54 176	-50 603
Amortization of plan change	100 513	58 495
Total	357 480	286 172
Employer's national insurance contributions	34 368	31 894
Total pension cost for the year	391 848	318 066

Parts of the pension costs are recharged to partners in licenses where the company is operator.

The following financial and actuarial assumptions have been made:

	2015	2014
Discount rate	2,70 %	2,30 %
Anticipated return on pension funds	3,30 %	3,20 %
Annual expected salary increases	2,50 %	2,75 %
National insurance basic amount adjustment	2,25 %	2,50 %
Pension adjustment	1,50 %	2,50 %

Pension and early retirement obligations

BP has pension obligation of NOK 653,8 million and early retirement obligation of NOK 3,6 million, total of NOK 657,4 million pr 31.12.2015.

Occupational pension

The company is required to have an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("lov om obligatorisk tjenestepensjon"). The company`s pension scheme meets the requirements of that law.

Note 10. Long-term liabilities

NOK 1 000	2015	2014
Intercompany debt	7 500 000	10 000 000

The loan is in Norwegian kroner, and interest is calculated according to standard Norwegian market conditions. The company has not provided security for any of the corporate debt, either short term or long term. All loans are due for repayment within five years.

Note 11. Removal and abandonment of wells

Pursuant to the conditions of the licenses in which the company participates, the State may demand that the installations are surrendered free of charge upon the cessation of production or when the license period expires. If this right is not exercised, the State can order the licensees to remove the installations.

There is a great deal of uncertainty associated with the cost estimates for any future removal of installations. The company makes provisions for future removal taking into account factors such as the probability, time aspects and cost estimates for the relevant offshore installations.

The discounted removal and abandonment obligation is estimated at 10 328 846 (NOK 1 000) of which 7 529 252 (NOK 1 000) has been allocated at 31 December 2015.

When estimates are revised, the effect is recognized in the income statement in the period in which the estimate is revised.

Note 12. Other short-term liabilities

NOK 1 000	2015	2014
Creditors and other expense accruals	1 169 196	1 397 719
Accrued holiday pay	112 235	112 739
Total other short-term liabilities	1 281 431	1 510 458

Note 13. Other information

Drilling obligations

As of 31 December 2014 BP has no commitment to the authorities to participate in drilling of exploration wells.

CO2 tax

1 January 1991 the authorities introduced a tax on the emission of environmentally harmful gases in connection with oil production (CO2 tax). The total tax paid by the company was NOK 115 million for 2015.

Guaranties

As at 31 December 2015, BP has a guarantee commitment to Stavanger kommune on withholding tax. At the end of 2015 the guarantee amounts to NOK 120 million.

Note 14. Oil, NGL and gas reserves

Estimated remaining reserves (BP Norge AS' share)

million barrels oil equivalents	2015	2014
Oil, NGL, gas	168	186

Reserves are produced over the field life. The concession periods extends from 2021 to 2033. The reserves are calculated on deterministic basis and wells/facilities programs. When estimating remaining reserves, an extension of the concession period is assumed if necessary. Estimated remaining reserves have been reduced as a result of production.

Concession periods expire as follows:

Ula	2028
Tambar	2021
Tambar Øst	2021
Skarv	2033
Valhall	2028
Hod	2021

Note 15. Transactions between related parties

All transactions with related parties are based on market conditions. We refer to note 7 and 10 regarding Inter-company receivables and debt, and note 4 related to remuneration to board members and management.

Below shows a summary of significant transactions with related parties (1000 NOK)

Company	**Relations**	**Transaction description**	**2015**	**2014**
BP Oil International	sister	Oil sale	-250 969	-2 583 032
BP Oil International	sister	NGL sale	-270 705	-446 002
BP Gas Marketing	sister	Gas sale	-1 803 282	-1 586 059
BP International Ltd	sister	Purchase of consultant- and shared services	255 280	216 878
BP Gas Marketing	sister	Purchase of CO2 quota	21 043	27 485
BP EOC Ltd	sister	Purchase of consultant- and shared services	48 407	22 109
BP Exploration Operating CO Ltd	sister	Purchase of consultant- and shared services	377 056	559 383
BP Corporate North America Inc	sister	Purchase of shared services	89 323	39 718
BP Shipping Ltd	sister	Platform supply vessel leases	92 542	14 132
Sum others	sisters	Purchase of consultant- and shared services, other	33 492	60 568

Purchases of goods and services are gross figures before allocation to our partners in the different production licenses.

Note 16. Stocks

Supplies and spare parts

NOK 1 000	2015	2014
Historical cost	363 513	427 071
Obsolete provision	91 813	97 995
Balance sheet value	271 699	329 076

Note 17. Leases and other obligations

Leases
BP has lease aggrements for rigs, vessels, commercial buildings and other operating assets. BP`s share of the obligations are pr. 31.12.15 NOK 2 576 millions undiscounted .

Year	2016	2017-2020	2020->
NOK 1 000	408	1279	889

Other obligations
BP has agreements for transport of gass, transport of NGL and other obligations pr 31.12.2015 of NOK 6 191 millions undiscounted.

Year	2016	2017-2020	2020->
NOK 1 000	708	3 454	2 029

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