Registration Document

OKEA AS

27.06.2018

Prepared according to Commission Regulation (EC) No 809/2004 - Annex XXVI.

Important notice

This Registration Document, prepared according to Commission Regulation (EC) No 809/2004 - Annex XXVI, is valid for a period of up to 12 months following its approval by the Financial Supervisory Authority of Norway (the "Norwegian FSA") (*Finanstilsynet)*. This Registration Document was approved by the Norwegian FSA on 27th June 2018. The Prospectus for issuance of new bonds or other securities may for a period of up to 12 months from the date of the approval consist of this Registration Document and a Securities Note and summary applicable to each issue and subject to a separate approval.

The Registration Document is based on sources such as annual reports and publicly available information and forward-looking information based on current expectations, estimates and projections about global economic conditions, the economic conditions of the regions and industries that are major markets for the Company's line of business.

A prospective investor should consider carefully the factors set forth in chapter 1 Risk factors, and elsewhere in the Prospectus, and should consult his or her own expert advisers as to the suitability of an investment in bonds, including any legal requirements, exchange control regulations and tax consequences within the country of residence and domicile for the acquisition, holding and disposal of bonds relevant to such prospective investor.

The manager and/or affiliated companies and/or officers, directors and employees may be a market maker or hold a position in any instrument or related instrument discussed in this Registration Document, and may perform or seek to perform financial advisory or banking services related to such instruments. The managers corporate finance department may act as manager or co-manager for this Issuer and/or guarantor in private and/or public placement and/or resale not publicly available or commonly known. Copies of this Registration Document are not being mailed or otherwise distributed or sent in or into or made available in the United States. Persons receiving this document (including custodians, nominees and trustees) must not distribute or send such documents or any related documents in or into the United States.

Other than in compliance with applicable United States securities laws, no solicitations are being made or will be made, directly or indirectly, in the United States. Securities will not be registered under the United States Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements.

The distribution of the Registration Document may be limited by law also in other jurisdictions, for example in Canada, Japan, Australia and in the United Kingdom. Verification and approval of the Registration Document by the Norwegian FSA implies that the Registration Document may be used in any EEA country. No other measures have been taken to obtain authorisation to distribute the Registration Document in any jurisdiction where such action is required, and any information contained herein or in any other sales document relating to bonds does not constitute an offer or solicitation by anyone in any jurisdiction in which such offer or solicitation is not lawful or in which the person making such offer or solicitation is not qualified to do so or to anyone to whom it is unlawful to make such offer or solicitation.

The Norwegian FSA has controlled and approved the Registration Document pursuant to the Norwegian Securities Trading Act, § 7-7. The Norwegian FSA has not controlled and approved the accuracy or completeness of the information given in the Registration Document. The control and approval performed by the Norwegian FSA relates solely to descriptions included by the Issuer according to a pre-defined list of content requirements. The Norwegian FSA has not undertaken any kind of control or approval of corporate matters described in or otherwise covered by the Registration Document.

The content of the Registration Document does not constitute legal, financial or tax advice and potential investors should seek legal, financial and/or tax advice.

Unless otherwise stated, the Registration Document is subject to Norwegian law. In the event of any dispute regarding the Registration Document, Norwegian law will apply.

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1. Risk factors

Investing in bonds involves inherent risks. Prospective investors should carefully consider, among other things, the risk factors set out in the Registration Document before making an investment decision.

A prospective investor should carefully consider all the risks related to OKEA AS and should consult his or her own expert advisors as to the suitability of an investment in securities of the Company. An investment in securities of the Company entails significant risks and is suitable only for investors who understand the risk factors associated with this type of investment and who can afford a loss of all or part of the investment. Against this background, an investor should thus make a careful assessment of the Company and its prospects before deciding to invest, including but not limited to the cost structure for both the Company and the investors, as well as the investors' current and future tax position.

RISKS RELATING TO THE COMPANY'S BUSINESS AND OPERATIONS

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

Prices for oil and gas may fluctuate substantially based on relatively small changes in the supply and demand for oil and gas, based on geo-political changes and -many other factors beyond the Company's control. Consequently, it is impossible to accurately predict future oil and gas price movements. Sustained lower oil and gas prices or price declines may inter alia lead to a material decrease in the Company's net production revenues. The Company may from time to time enter into hedging arrangements to offset the risk of revenue losses if commodity prices decline. However, such arrangements may be expensive and there can be no assurance that hedging will be available or continue to be available on commercially reasonable terms. In addition, hedging itself carries certain risks, including expenses associated with terminating any hedging agreements. Further, sustained lower oil and gas prices may also cause the Company to make substantial downward adjustments to its oil and gas reserves. If this occurs, or the Company's estimates of production or economic factors change, the Company may be required to write-down the carrying value of its proved oil and gas properties for impairments. In addition, the depreciation of oil and gas assets charged to its income statement is dependent on the estimate of its oil and gas reserves. Further, certain development projects which are or become of substantial importance to the Company 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. Additionally, if oil and gas prices remain depressed over time, it could reduce the Company's ability to raise new debt or equity financing or to refinance any outstanding loans on terms satisfactory, or at all.

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

Included in this Registration Document is information relating to the reserves and resources of certain of the Company's assets.

Many of the factors in respect of which assumptions are made when estimating reserves and resources are beyond the Company's control and therefore these assumptions may prove to be incorrect over time.

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

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

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

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

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

Developing a hydrocarbon production field, in particular the development of contingent resources into reserves

Developing a hydrocarbon production field, in particular the development of contingent resources into reserves, requires significant investment, some times over several decades, to build the requisite operating facilities, drilling of production wells along with implementation of advanced technologies for the extraction and exploitation of hydrocarbons with complex properties. Making these investments and implementing these technologies, normally under difficult conditions, can result in uncertainties about the amount of investment necessary, operating costs and additional expenses incurred as compared with the initial budget, thereby negatively affecting the business, prospects, financial condition and results of operations of the Company. Further, with respect to contingent resources, the amount of investment needed may be prohibitive, such that conversion of resources into reserves may not be commercially viable. The Company may be unable to obtain needed capital or financing on satisfactory terms. If the Company's revenues decrease, it may have limited ability to obtain the capital necessary to sustain operations at current levels. If the Company's available cash is not sufficient, a curtailment of its operations relating to development of its prospects could occur, which in turn could lead to a decline in its oil and natural gas reserves, or if it is not possible to cancel or stop a project, be legally obliged to carry out the project contrary to its desire or with negative economic impact. Further, the Company may inter alia fail to pay required cash calls and thus breach license obligations, which again could lead to adverse consequences. All of the above may have a material adverse effect on the Company and its financial position.

Failure to fulfill the SPA relating to an additionally 5% may have an adverse affect on the Company

Pursuant to the sale and purchase agreement for the Yme transaction, the seller is entitled to terminate the agreement if the Company is in material breach of its obligations under the agreement, including obligations after the closing of the transaction, such as obligations to pay future instalments of consideration. Should this occur, the Company may potentially have to transfer the 5% interest back against repayment of paid consideration, in which case the Company may lose the potential upside in the 5% interest which may have a negative effect on the Company's future financial position.

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

The future success of the Company depends in part on its ability to find and develop or acquire additional reserves that are economically recoverable, which is dependent on oil and gas prices. Oil and gas exploration and production activities are capital intensive and inherently uncertain in their outcome. 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. Few prospects that are explored are ultimately developed into producing oil and gas fields. 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 on the Company's part to recover its costs and generate profits from its exploration and production activities could have a material adverse effect on its business, results of operations, cash flow and financial condition.

Additionally, producing oil and natural gas reservoirs, particularly in the case of mature fields, are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, the Company's future oil and natural gas reserves and production and, therefore, its cash flow and results of operations are highly dependent upon the Company's success in efficiently developing and exploiting its current properties and economically finding or acquiring additional recoverable reserves. The Company may not be able to develop, find or acquire additional reserves to replace its current and future production at acceptable costs. If the Company is unable to replace its current and future production, the value of its reserves will decrease, and its business, financial condition and results of operations would be adversely affected.

The Company's current production and expected future production is concentrated in a limited number of offshore fields

Currently, all of the Company's production comes from Ivar Aasen. The Company expects that a significant proportion of its future production will come from the Yme field. If mechanical or technical problems, storms, shutdowns or other events or problems affect the current or future production on one of these 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 anticipated, this may result in material adverse effects for the Company, including on the Company's ability to fulfil its obligations under the bonds, make new investments and raise further financing.

The Company's current or future development projects are associated with risks relating to delays, cost inflations, potential penalties and regulatory requirements and the estimated development costs and time to achieve first oil for the Yme Licenses may be substantially exceeded and/or delayed

Development projects inter alia involve complex engineering, procurement, construction work, drilling operation to be carried out and governmental approvals obtained prior to commencement of production. 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. The complexity of offshore development projects also makes them very sensitive to delays or costs increases. For the Company, this will currently in particular apply to the Yme and Grevling fields. Current or future projected target dates for production may be delayed and significant cost overruns may incur. The Company's estimated exploration costs are subject to a number of assumptions that may not materialize. Such factors may again impact on to what extent fields to be developed is fully funded or remain commercially viable, and consequently could result in breach by the Company of its obligations and/or require the Company to raise additional debt and/or equity. Any delays, cost increases or other negative impact relating to the current or future development projects of the Company, may have a material adverse effect on its business, results of operations, cash flow, financial condition and prospects.

The Company's hydrocarbon production may be restricted, delayed or terminated due to a number of internal or external factors

The Company's hydrocarbon production may be restricted, delayed or terminated due to a number of internal or external factors, among which are malfunctions of hydrocarbon discharge or production facilities, administrative delays (particularly in the approval of development projects by public authorities), shortages or delays in the availability of drilling and/or production rigs and delivery of equipment and materials, pressure or irregularities in geological formations, equipment failures or accidents or adverse weather conditions or malicious actions. In particular, production from the Yme field will in part depend on the functionality of existing facilities, such as pipelines, wells and umbilicals, which have not been in use for some time and which the Company cannot be certain will function properly. These factors may have a material adverse effect on the Company's cash flow as well as on its business, prospects, financial condition or results of operations and consequently affect the Company's ability to serve its debts and fulfil its obligations under the Bonds and otherwise.

The Company's operations are dependent on compliance with obligations under licenses, joint operating agreements and field development plans

In all production licenses on the NCS there are obligations amongst the parties in the joint venture and obligations between the production license and the authorities. Failure to comply with the obligations under the licenses may lead to fines, penalties, restrictions, revocation of licenses and termination of related agreements. A failure to comply with payment obligations (cash calls) under joint operating agreements (and unitization agreements) for the Company's licenses, may lead to penal interest on the defaulted amount, loss of voting rights and information within the license and a right for the other licensees to acquire the Company's participant interest on terms that are unfavourable to the Company and disconnected from the value of the license interest. Further, if other joint venture partners default on their payment obligations (cash calls), the Company may have to increase its interest level in the relevant field, which in turn will result in a corresponding increase in the Company's exposure and investment obligations towards the relevant field. Also, the Company has been approved as an operator on the NCS. Although future operatorship is performed based on a "no gain, no loss" principle, the Company's license partners 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.

All such risks, non-compliance, sanctions or losses could have a material adverse effect on the Company and may result in the Company not being fully funded to meet such increased exposure and obligations and consequently could result in breach by the Company of its obligations and/or require the Company to raise additional debt and/or equity.

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

Where the Company is not the operator of fields in which it has an interest, it has limited control over the management of the assets and mismanagement by the operator or disagreements with the operator as to the most appropriate course of action may occur, which again may result in significant delays, losses or increased costs to the Company. There are, however, routines in mandatory Joint Operating Agreements that regulate the relationship within the license and how the operator or others may behave or act. There is, however, a risk that 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. In these circumstances, it may not be possible for such activities to be undertaken by the Company alone or in conjunction with other participants. Inversely, decisions by the other partners to engage in certain activities, may also be contrary to the Company's desire not to commence such activities and may require the Company to incur its share of costs in relation thereto, or that the other partners may enforce decisions which will delay or affect the profitability of a project. This is especially an inherent risk in fields under development where the Company only holds a minority interest. Other participants in the Company's licenses may default on their funding obligations. 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. The Company may not have the resources to meet these obligations. Further, the license partners are jointly and severally responsible to the Norwegian Government for financial obligations arising out of petroleum activities pursuant to a license. If any of the Company's partners become insolvent or otherwise unable to pay debts as they come due, the license interest awarded to them may be revoked by the relevant government authority who will then reallocate the license interest. There can be no assurance that the Company will be able to continue operations pursuant to these reclaimed licenses or that any transition related to the reallocation of the license would not materially disrupt the Company's operations.

The Company is subject to risks relating to capacity constraints and cost inflation in the service sector and lack of availability of required services and equipment

The Company is highly reliant upon services, goods and equipment provided by contractors and other companies to carry out its operations (including current and planned exploration and development projects). There is a continuing risk for capacity constraints and cost inflation in the service sector. Any non-performance, delays or faulty deliveries by contractors, or any other failure to obtain necessary services, goods or equipment, at all or at a reasonable cost, may expose the Company to significant delays, cost increases or liability, which may again lead to material adverse effects for the Company. Further, the Company's contractors and other companies may potentially be adversely affected by market conditions. If the Company's contractors, their suppliers or other companies should be unable to respect their obligations (towards the Company or others), become insolvent or otherwise unable to pay debts as they come due, this could lead to material adverse effects for the Company.

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

The Company is dependent on capacity (whether through pipelines, tankers or otherwise) to transport and sell its oil and gas production. 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. 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 access to third-party infrastructure and necessary capacity bookings are unavailable or unavailable at an economically justifiable cost, the Company's income relating to the sale of oil and gas may be reduced, which may have a material adverse effect on the Company.

The Company is vulnerable to adverse market perception

The Company 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 contracts, fiduciary or regulatory responsibilities, allegations of such activities, negative publicity, or the association of any of the above with the Company could materially adversely affect its reputation and the value of its brand, as well as its business, results of operations, cash flow and financial condition.

The Company faces risks related to decommissioning activities and related costs

There are significant uncertainties relating to the estimated liabilities, costs and time for decommissioning of the Company' current and future licenses. Such liabilities are derived from legislative and regulatory requirements and require the Company to make provisions for such liabilities. The oil and gas industry still has little experience of decommissioning petroleum infrastructure on the Norwegian Continental Shelf.

The Company is jointly and severally liable with its license partners to the Norwegian Government for all decommissioning costs and liabilities of each license in which the Company holds an interest. In Norway, there is no obligation or tradition for license partners to provide security for their respective share of decommissioning liabilities ahead of actual decommissioning. Furthermore, a licensee assigning its interest in a license remains secondarily liable for decommissioning costs related to facilities existing at the time of assignment. For such secondary liability there is an established practice for providing a decommissioning guarantee or other security. In the future, the Company may hold interest in fields that straddle the boundary between UK and Norway and the Company may therefore have responsibilities under or become liable for decommissioning obligations also under UK legislation.

It is, therefore, difficult to forecast accurately the costs that the Company will incur in satisfying decommissioning liabilities. No assurance can be given that the anticipated cost and timing of removal are correct and any deviation from current estimates or significant increase in decommissioning costs relating to the Company's previous, current or future licenses, may have a material adverse effect on the Company.

The Company's ability to sell or transfer license interests may be restricted by provisions in its joint operating agreements including pre-emption rights, if any, or applicable legislation

The Company's exit in relation to any particular oil and gas interest may be subject to the prior approval of its commercial partners pursuant to joint operating agreements, unitization agreements and approval from the relevant authorities, thus restricting the Company's ability to dispose of, sell or transfer a license interest and make funds available when needed.

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

All phases of oil and gas activities present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and national laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, and releases or emissions of various substances. The legislation also requires that wells and facility sites are operated, maintained and abandoned to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties in addition to loss of reputation. Any pollution may give rise to material liabilities and may require the Company to incur material costs to remedy such discharge. No assurance can be given that current or future environmental laws and regulations 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 have a material adverse effect on the Company.

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.

The Company is exposed to political and regulatory risks, including risks and uncertainties relating to the planned regional (area) electrification of the Utsira High in relation to the Ivar Aasen field

The oil and gas industry is subject to extensive government policies, standards, regulations and requirements. No assurance can be given that future political conditions, existing legislation, new interpretation of existing legislation or changes in administrative practice or policies, will not result in a reduction of income, curtailment of production, delays or a material increase in operating costs and capital expenditure or otherwise adversely affect the Company. In particular, the Company is exposed to a risks relating to the planned regional (area) electrification of the Utsira High in relation to the Ivar Aasen field, which includes uncertainties related to the actual cost of electrification, allocation of such costs between the partners in the fields on the Utsira High and the proposed timeline for electrification of the Utsira High.

A failure to comply with applicable legislation, regulations and conditions or orders issued by the regulatory authorities, may lead to fines, penalties, restrictions, withdrawal of licenses and termination of related agreements. Additionally, the Company is dependent on receipt of discretionary government approvals, decisions and permits to develop and produce its assets. Further, the Company may be unable to obtain, renew or extend required drilling rights, licenses (including production licenses), permits and other authorizations and these may also be suspended, terminated or revoked prior to their expiration. The relevant authorities may also stipulate conditions for any such extension or for not revoking any licenses or permits. 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 its contractual arrangements or its ability to meet its contractual obligations.

Maritime disasters, employee errors and other operational risks may adversely impact the Company's reputation, financial condition and results of operations

The Company's offshore operations are subject to all the risks common in its industry, including inter alia encountering unexpected rock formations or pressures, seismic shifts, blowouts, pollution, explosions, fires and equipment damage or failure. The facilities on offshore fields will also be subject to the hazards inherent in marine operations, such as inter alia capsizing, sinking, grounding and damage from severe weather conditions. Also, even though the Company's employees are well supervised, trained and experienced, personnel and employee errors and mistakes may take place. If any of these events were to occur, they could, among other adverse effects, result in environmental damage, injury to persons, loss of life, a failure to produce oil and/or gas in commercial quantities, delays, shut-down of operations or other damage. These events can also put at risk some or all of the Company's licenses and could inter alia result in the Company incurring significant civil liability claims, significant fines as well as criminal sanctions. In the Company's capacity as licensee, it is inter alia subject to liability provisions under the applicable statutory and regulatory regimes of the jurisdictions where the Company operates.

Any of these circumstances could adversely affect the operation of the Company's licenses, and result in loss of revenues or increased costs and adversely affect the Company's profitability.

The Company's insurance or indemnities may not adequately cover all risks, liabilities or expenses that could result from its operations

The Company's offshore oil and gas operations are subject to all the significant risks and hazards typically associated with such operations. The Company is not necessarily fully insured against all risks it may face (it has for example currently not taken out business interruption insurance). Furthermore, not all mentioned risks are insurable, or only insurable at a disproportionately high cost. The nature of the hazards and risks typical for the Company's industry is such that liabilities could materially exceed policy limits or not be insured at all, which may result in substantial financial liability or losses. Any uninsured loss or liabilities, or any loss and liabilities exceeding the insured limits, may have a material adverse effect on the Company.

The Company may experience conflicts of interest

Some of the directors, officers and principal shareholders of the Company are or may become engaged in other oil and gas interests (including interests relating to oil and gas services) on their own behalf and on behalf of other companies resulting in a conflict of interest or direct competition with the Company. Such conflicts, if any, will be subject to the procedures and remedies under Norwegian company law (or any similar, foreign laws), but this may not prevent adverse effects for the Company with regard to such conflicts. The Company's directors, officers and principal shareholders may not devote their time on a full-time basis to the affairs of the Company as a result of such conflicts. Certain members of the Company's board of directors and senior management 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 and thereby the Company.

The risk of losing key employees

The Company only has a very limited number of employees and executives. The loss of key employees could adversely affect the Company's ability to operate. The Company believes that its success depends on the continued service of its key employees, as well as its ability to hire additional key employees, when and as needed. The unexpected loss of the services of any of the key employees, or the Company's failure to find suitable replacements within a reasonable period of time thereafter, could have a material adverse effect on the Company's ability to execute its business plan and therefore, on its financial condition and results of operations.

The Company is exposed to risks relating to unionized labor and general labor interruptions

Strikes, labor disruptions and other types of conflicts with employees including those of the Company's independent contractors or their unions may occur in relation to the Company's operations. 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.

Changes in foreign exchange rates may affect the Company's results of operations and financial position

The Company is exposed to market fluctuations in foreign exchange rates. The Company may from time to time enter into foreign currency exchange hedging arrangements to manage the risk of foreign currency exposure and may also be required to provide security for such derivative transactions. Such security if provided could make it difficult for the Company to service its debt.

RISKS RELATING TO THE OIL AND GAS INDUSTRY IN WHICH THE COMPANY OPERATES

The market in which the Company operates is highly competitive

The Company competes with a substantial number of other companies with larger technical staffs and greater resources, inter alia in acquiring (prospective) oil and gas licenses and attempting to secure drilling rigs and other equipment or services necessary for operation or projects. As a result of this competitive environment, the Company may inter alia be unable to acquire suitable licenses or licenses on terms that it considers acceptable, or equipment or services it requires may be in short supply. As a result, the Company's revenues may decline over time.

The oil and gas industry is characterized by rapid and significant technological advancements, and the Company may not be able to keep pace

As others use or develop new technologies, the Company may be placed at a competitive disadvantage over time or may be forced by competitive pressures to implement those new technologies at substantial costs. The Company may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. Further, one or more of the technologies used by the Company now or in the future may become obsolete. In addition, new technology implemented by the Company may have unanticipated or unforeseen adverse consequences, either to its business or the industry as a whole.

Climate change abatement legislation or protests against fossil fuel extraction may have a material adverse effect on the oil and gas industry

Continued political attention to issues concerning climate change, the role of human activity in it and potential mitigation through regulation could have a material impact on the Company's business. International agreements, national and regional legislation, and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. Given the Company's operations are associated with emissions of "greenhouse gases", these and other greenhouse gas emissions related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted by particular countries. As such, climate change legislation and regulatory initiatives restricting emissions of greenhouse gases may adversely affect its operations, the Company's cost structure or the demand for oil and gas. Such legislation or regulatory initiatives could have a material adverse effect by diminishing the demand for oil and gas, increasing the Company's cost structure or causing disruption to its operations by regulators. In addition, the Company may be subject to activism from groups campaigning against fossil fuel extraction, which could affect its reputation, disrupt its campaigns or programs or otherwise negatively impact the Company's business.

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

The Company may be materially and adversely affected by, amongst other things, the general state of the economy and business conditions, the occurrence of recession, inflation, adverse credit markets, fluctuations in operating expenses, technical problems, work stoppages or other labour difficulties. Weak global or regional economic conditions may negatively impact the business of the Company in ways that it cannot predict. Global financial markets and economic conditions have been severely disrupted and volatile in recent years and remain subject to significant vulnerabilities, such as the rapid accumulation of public debt, continued deleveraging in the banking sector and a limited supply of credit. The Company may inter alia experience difficulties obtaining financing commitments or be unable to fully draw on the capacity under committed loans it arranges in the future if its lenders are unwilling to extend financing to it or unable to meet their funding obligations due to their own liquidity, capital or solvency issues. The Company cannot be certain that financing will be available on acceptable terms, or at all. If financing is not available when needed, or is available only on unfavourable terms, the Company may be unable to meet its future obligations as they come due. The Company's failure to obtain such funds could have a material adverse effect on its business, results of operations and financial condition, as well as its ability to service its indebtedness.

FINANCIAL RISKS AND RISKS RELATED TO DEBT OBLIGATIONS

The Company is exposed to credit risk

The Company may be exposed to financial loss if counterparties to contracts fail to meet their obligations. If significant amounts are not paid this could have a material adverse impact on the Company.

The Company may incur substantial debt in the future, which may make it difficult for it to service its debt

The Company may incur substantial indebtedness in the future, either under the terms of the Bond Agreement, as additional bonds allowed under the terms of the Bond Agreement, or as subordinated debt. Under any circumstance, if the Company incurs new debt or other obligations, the related risks that it faces, will increase. In addition, the Company is currently under and may in the future incur obligations that do not constitute indebtedness as defined under the agreements governing the debt arrangements. The degree to which the Company is leveraged could have important consequences to its business and holders of the bonds, including, but not limited to:

- making it difficult for to satisfy the Company's obligations with respect to the bonds or other indebtedness;

- increasing the Company's vulnerability to, and reducing its flexibility to respond to, general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of the Company's cash flow from operations to the repayment of the principal of its indebtedness and interest on such indebtedness, thereby reducing the availability of such cash flow;
- limiting the Company's ability to obtain additional financing to fund working capital, capital investments, acquisitions, debt service requirements, business ventures, or other general corporate purposes;
- limiting the Company's flexibility in planning for, or reacting to, changes in its business and the competitive environment and the industry in which the Company does business; and
- adversely affecting the Company's competitive position if its debt burden is higher than that of its competitors.

The Company will require a significant amount of cash to service future debt and sustain its operations, and its ability to generate sufficient cash depends on many factors beyond its control

The Company's ability to make payments on, or repay or refinance, any debt (including the bonds), and to fund working capital and capital investments, will depend on its future operating performance and ability to generate sufficient cash. This depends on the success of its business strategy and on general economic, financial, competitive, market, legislative, regulatory, technical and other factors as well as the risks discussed in these "Risk Factors", many of which are beyond the Company's control. The Company cannot assure that its business will generate sufficient cash flow from operations or that future debt and equity financings will be available to it in an amount sufficient to enable it to pay its debt, or to fund its other liquidity needs. The Company cannot give assurance that it will be able to refinance any debt on commercially reasonable terms or at all. Any failure by the Company to make payments on debt on a timely basis would likely result in a reduction of its credit quality, which could also harm its ability to incur additional indebtedness. There can be no assurance that any assets that the Company may elect to sell can be sold or that, if sold, the timing of such sale will be acceptable and the amount of proceeds realized will be sufficient to satisfy its debt service and other liquidity needs.

If the Company is unsuccessful in any of these efforts, it may not have sufficient cash to meet its obligations, which could cause an event of default under any debt arrangements and could result in the debt being accelerated, lending reserves and certain bank accounts being frozen, triggering of cross-default provisions, enforcement of security and the companies of the Company, including the Company, being forced into bankruptcy or liquidation, which could result in an investor losing its investment in the Company's shares or bonds in its entirety.

The Company is subject to restrictive debt covenants that may limit the Company's ability to finance its future operations and capital needs and to pursue business opportunities and activities

The Bond Agreement will restrict, among other things, the Company's ability to:

- incur additional debt and issue guarantees;
- make certain payments, including dividends and other distributions, with respect to outstanding share capital;
- repay or redeem subordinated debt or share capital;
- create or incur certain liens and security arrangements;
- make certain investments or loans;
- sell, lease or transfer assets;
- acquire assets or companies;
- expand into unrelated businesses; and
- merge or consolidate with other entities.

All of these limitations are subject to significant exceptions and qualifications. The Company's compliance with these covenants could reduce its flexibility in conducting its operations, particularly by:

- affecting the Company's ability to react to changes in market conditions, whether by increasing its vulnerability in relation to unfavorable economic conditions or by preventing the Company from profiting from an improvement in those conditions;
- affecting the Company's ability to pursue business opportunities and activities that may be in its interest;
- limiting the Company's ability to obtain certain additional financing in order to meet its working capital requirements, make investments or acquisitions and carry out refinancings; and
- forcing the Company to dedicate a significant portion of its cash flows to payment of the sums due for such loans, thus reducing its ability to utilize its cash flows for other purposes.

The Company's working capital needs are difficult to forecast and may be subject to significant and rapid increases which could result in additional financing requirements that the Company may not be able to obtain on satisfactory terms or at all

The Company is unable to predict with certainty its working capital needs going forward. This is primarily due to possible new acquisitions or divestments of current assets, large capital requirements for general operating expenses, exploration and development expenditures. As the future level of income is also difficult to predict with any certainty due to uncertainties concerning prices for oil and gas and actual production levels, forecasting capital requirements is difficult and subject to substantial uncertainty, which could adversely affect the Company's ability to obtain required funds on satisfactory terms, or at all.

2. Persons responsible

PERSONS RESPONSIBLE FOR THE INFORMATION

Persons responsible for the information given in the Registration Document are as follows:
OKEA AS, Ferjemannsveien 10, 7042 Trondheim, Norway.

DECLARATION BY PERSONS RESPONSIBLE

OKEA AS confirms that, having taken all reasonable care to ensure that such is the case, the information contained in the Registration Document is, to the best of its knowledge, in accordance with the facts and contains no omission likely to affect its import.

27.06.2018

OKEA AS

3. Definitions

"Agreement for petroleum activities"	-	Companies being awarded a production licence on the Norwegian Continental Shelf are obliged to enter into an Agreement for petroleum activities, cf. the Norwegian Petroleum Act Section 3-3 fourth paragraph. The agreement consists of two parts: Special provisions and an attachment containing enclosure A – Joint Operating Agreement and enclosure B – Accounting Agreement.
"Bond Agreement"	-	Means the Bond Terms for ISIN NO0010810062.
"boe"	-	Barrel of oil equivalent.
"boed"	-	Barrels Of Oil Equivalent Per Day.
"Company" / "Issuer" / "OKEA"	-	OKEA AS - with registration number 915 419 062.
"GoM"	-	Gulf of Mexico.
"Group"	-	Means the Issuer and its subsidiaries from time to time. At the date of this Registration Document, the Issuer has no subsidiaries.
"Joint Operating Agreements"	-	Part of the mandatory agreement for petroleum activities that companies being awarded a production licence on the Norwegian Continental Shelf are obliged to enter into cf. the Norwegian Petroleum Act Section 3-3 fourth paragraph, which regulates the working relationship within the joint venture, including but not limited to voting rules, organisation of work, and responsibilities and liabilities for the licensees.
"mmboe"	-	Million Barrels of Oil Equivalent
"mmbbl"	-	Million Barrels
"NCS"	-	Norwegian Continental Shelf
"PDO"	-	Plan for Development and Operation
"Prospectus"	-	The Registration Document together with the Securities Note and the Summary.
"Registration Document"	-	This registration document dated 27.06.2018.
"Securities Note"	-	Document to be prepared for each new issue of bonds under the Prospectus.
"Summary"	-	Document to be prepared for each new issue of bonds under the Prospectus.
"UK"	-	United Kingdom.
"UKCS"	-	The UK Continental Shelf.
"USD"	-	US Dollars.
"WI"	-	Working Interest

4. Statutory auditors

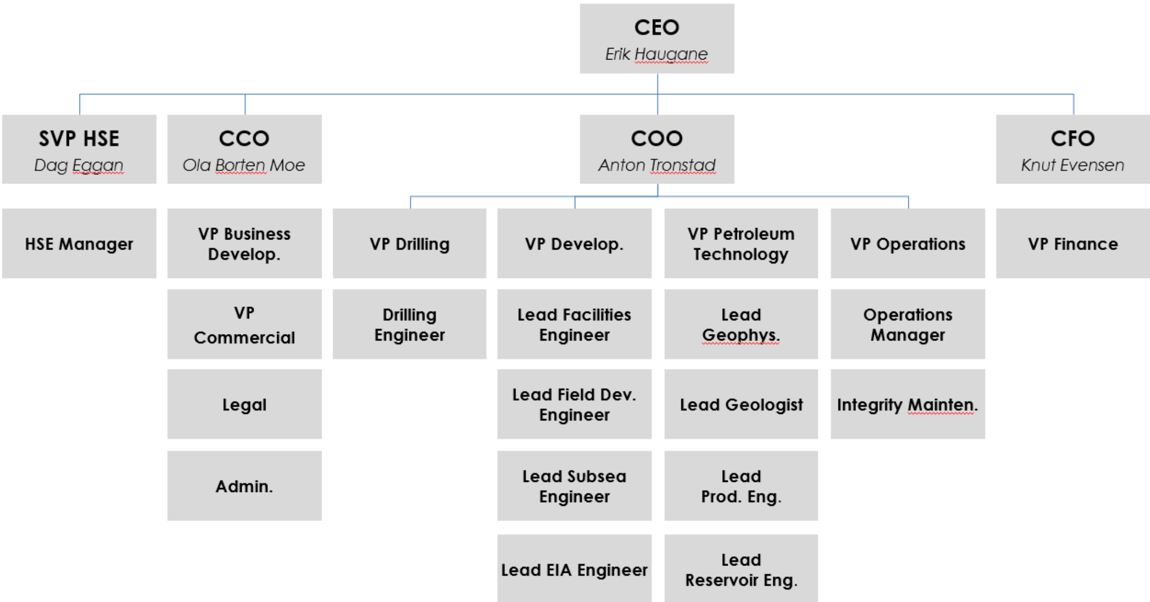
The Company's independent auditor for the period, which has covered the historical financial information in this Registration Document, has been PricewaterhouseCoopers AS ("PwC") with registration number 987 009 713, and business address at Dronning Eufemias gate 8, N-0191 Oslo, Norway.

PwC is a member of the Norwegian Institute of Public Accountants.

5. Information about the Issuer

OKEA AS is a limited liability company organised and existing under the laws of Norway pursuant to the Norwegian Companies Act, the Norwegian Petroleum Act and the Petroleum Taxation Act. OKEA's operations in Norway are taken place in petroleum licenses, govern by the Joint Operating Agreements. The Company was incorporated in Norway on 29 April 2015, and the organisation number in the Norwegian Register of Business Enterprises is 915 419 062. The Company's registered name is OKEA AS and the commercial name is OKEA. OKEA's registered office is in the municipality of Trondheim, located at Ferjemannsveien 10, N-7042 Trondheim, Norway and the Company's main telephone number at this address is +47 73 52 52 22
Website: www.okea.no.

OKEA is a pure Norwegian development & production company and according to the Company's Articles of Association paragraph § 3, the business of the Company is petroleum activities on the Norwegian continental shelf, including development and production of oil and gas, and all other business activities as are associated with the above objectives, and share subscription or participation by other means in such operations alone or in cooperation with others. OKEA is approved as operator on the Norwegian Continental Shelf and the Company has 26 employees:



OKEA was founded with capital contribution from four members of the management, as well as with capital originating from funds and strategic investments managed by Seacrest Capital Group, a global fund manager, specialising in E&P investments.

OKEA does not primarily intend to explore for petroleum but utilize the results of the previous and ongoing exploration activities. The Company may be involved in near field exploration activities, primarily with the objective of adding resources to existing discoveries. Among all the discoveries not developed, there are millions of barrels of oil that OKEA is committed to bring on stream in a strategic cooperation with key service companies.

OKEA aims to acquire shares in licenses with oil discoveries that lack a development plan. The Company is committed to reducing field development cost and operational cost in order to make also smaller discoveries economical viable.

5.1 Regulatory framework

Norway has put in place an extensive legislation that requires companies to obtain licences and approval from the competent authorities for all phases of petroleum activities.

The Petroleum Act (Act of 29 November 1996 No. 72 relating to petroleum activities) provides the general legal basis, including the licensing system that gives OKEA and other companies rights to engage in petroleum operations. The Act establishes that the Norwegian state has the proprietary right to subsea petroleum deposits on the Norwegian continental shelf.

At the date of this Registration Document, OKEA has all necessary concessions and legal, economic and environmental conditions in place.

5.1.1 The life cycle - From area opening procedures to the end of production

Petroleum activities can be divided into several phases. An area must be opened for petroleum activities before any operations are permitted. The first phase is exploration, when any subsea petroleum resources are mapped and proved. If commercially viable discoveries are made, activities enter a new phase with the aim of developing the field and producing from it, at the same time ensuring sound resource management and maximising value creation. When it is no longer possible to produce profitably from a field, operations must be closed down and the installations disposed of (made safe in place or removed).

5.1.2 Opening new areas for petroleum activities

Before licences can be awarded for petroleum activities, the area where activities are planned must have been officially opened. As part of this process, the Ministry of Petroleum and Energy is required to carry out an impact assessment including an evaluation of the possible economic, social and environmental impacts of the activities. During an opening process, the authorities ensure that they have an overview of all relevant arguments for and against petroleum activities in the area in question. During an opening process, all relevant arguments for and against petroleum activities in the area in question are taken into account.

In addition, the general public and the parties affected are given an opportunity to put forward their views. A resource assessment of the area is also made as part of the opening process. Decisions on whether or not to open new areas for petroleum activities are made by the Storting (Norwegian parliament). Impact assessments and opening of new areas are governed by Chapter 3 of the Petroleum Act and Chapter 2a of the Petroleum Regulations.

5.1.3 Award of production licences

OKES primary strategy is not to participate in licencing rounds, but from time to time the Company will take part in applications, particularly if it sees potential near existing discoveries or fields.

A production licence grants exclusive rights to exploration, exploration drilling and production of petroleum in the area covered by the licence. It also regulates other rights and duties of the licensees vis-à-vis the Norwegian state. Production licences supplement the provisions of the legislation and set out detailed conditions for activities in a particular area. Licensees become the owners of a share of the oil and gas produced proportional to their share of the ownership. An example of a standard production licence with appendices is available on the website of the Ministry of Petroleum and Energy. https://www.regjeringen.no/en/find-document/dep/OED/Laws-and-rules-2/Rules/konsesjonsverk/id748087/

Production licences are normally awarded through licensing rounds, in which the Ministry announces that companies can apply for production licences in certain geographical areas (blocks). The announcement procedures, who can apply, the content of applications and application procedures are governed by Chapter 3 of the Petroleum Act and Chapter 3 of the Petroleum Regulations. The Norwegian Petroleum Directorate has drawn up detailed guidelines for applications in addition. These are available on the Directorate's website.

On the basis of the applications received, production licences are awarded to groups of companies. Awards are made on the basis of fair, objective and non-discriminatory criteria that are announced in advance.

In each case, the Ministry designates an operator for the joint venture, and this company is responsible for the operational activities authorised by the licence. The licensee group finances the activities jointly. Each licensee is expected to make use of its own particular expertise, and all the licensees have a responsibility for controlling the operator's activities.

5.1.4 Licensing rounds

Two types of licensing rounds have been established to ensure adequate exploration of both mature and frontier areas of the Norwegian continental shelf. All areas that are open and therefore available for petroleum activities may be announced in numbered licensing rounds or through the system of awards in predefined areas (APA). The parts of the shelf to be included in each of the two types of rounds are determined on the basis of expert assessments of the maturity of different areas, particularly in relation to the need for stepwise exploration and utilisation of time-critical resources.

The main differences between numbered licensing rounds and APA rounds are in the stages before licensing rounds are announced; after this stage, the procedures and award process are very similar.

5.1.4.1 Numbered licensing rounds in frontier areas

Numbered licensing rounds are used for frontier areas, where there is limited knowledge of the geology, greater technical challenges than in mature areas and a lack of infrastructure.

The strategy for licensing rounds in recently opened and frontier areas has generally been based on the principle of step by step or sequential exploration. This means that the results gained from exploration wells drilled in selected blocks in an area should be available before any new blocks are announced in the same area. In this way, it is possible to map large areas with a relatively small number of wells.

Before a numbered licensing round is announced, there is a nomination process. This starts when all the oil companies on the Norwegian shelf, both existing licensees and prequalified companies, are asked to nominate blocks for inclusion in the licensing round.

There is a limit on the number of blocks companies can nominate, and they are asked to give grounds for their selections based on their own geological assessments. The Norwegian Petroleum Directorate reviews all the nominations it receives and makes its own geological assessment.

Next, the Directorate sends its recommendations for the blocks to be included in the licensing round to the Ministry of Petroleum and Energy. In the 20th licensing round, the Directorate's recommendations were for the first time submitted to public consultation, and this has become normal procedure in subsequent licensing rounds. The Government makes the final decision on which blocks are to be announced, including any special environmental and fisheries-related requirements for petroleum activities.

After the applications have been received, they are assessed in relation to criteria announced in advance and negotiations are held with the companies. The Government decides which licences to award to which companies, and the final awards are formally made by the King in Council.

Numbered licensing rounds have been held since 1965, and are normally announced every other year.

5.1.4.2 Awards in predefined areas (APA) in mature areas

APA licensing rounds are used for mature areas, where petroleum activities have been in progress for many years. In such areas the geology is well known, there are fewer technical challenges, and there is well developed or planned infrastructure.

As new areas mature, the APA areas can be expanded within the framework for petroleum activities in each sea area. The areas of the Norwegian shelf where most is known about the geology are included on the basis of expert assessments. No acreage is withdrawn from the APA areas, although exceptions can be made if important new information becomes available.

There is no nomination step in APA rounds. Before a round is announced, the Petroleum Directorate sends its recommendations on the inclusion of any new blocks in the APA areas, based on expert assessments, to the Ministry of Petroleum and Energy. The final proposal for APA areas to be announced in the licensing round is submitted to public consultation.

As in numbered licensing rounds, the Government makes the final decision on which blocks are to be announced, including any special environmental and fisheries-related requirements for petroleum activities. Companies can apply for licences for all acreage in APA areas not already covered by production licences.

After the applications have been received, they are assessed in relation to criteria announced in advance and negotiations are held with the companies. Which licences to be offered is thereafter decided by the Government and the final awards are made by the King in Council.

The APA system was introduced in 2003 to ensure that profitable resources in mature areas are proven and recovered before existing infrastructure is shut down. If this is not done, profitable resources may remain unrecovered because the deposits are too small to justify the building of separate infrastructure. Sixteen APA licensing rounds have so far been initiated (APA 2003-2018).

APA licensing rounds are announced annually.

5.1.5 The exploration phase

Once awarded, a production licence applies for an initial period of up to ten years, which is reserved for exploration activity. To ensure that the area to which the production licence applies is explored properly, the licensee group is obliged under the terms of the licence to carry out a work programme. The obligatory work commitment of the production licence may include geological and/or geophysical activities and exploration drilling. The licence includes deadlines for carrying out the different activities.

If all the licensees agree, they may relinquish the production licence once they have completed the obligatory work. Areas relinquished in this way can later be awarded to new licensee groups. This ensures that mapping of the petroleum resources in different parts of the Norwegian continental shelf is steadily improved. As a result, we now have extensive knowledge of the subsea resources in many areas.

5.1.6 The development and operation phase

If the licensees make a discovery and wish to continue work under the licence after they have fulfilled their work obligation, they are entitled to an extension period for the licence. The duration of the extension period is determined by the Ministry of Petroleum and Energy when the licence is awarded, and in most cases is 30 years.

Field development and operation take place during the extension period. If the licensees wish to develop a field, they are obliged to do this in a responsible way. The companies are responsible for planning and implementing development projects, but each project requires prior approval from the Ministry. Major and/or important projects are put before the Storting before the Ministry gives its approval.

The licensees must submit a plan for development and operation (PDO) of a new deposit to the Ministry as a basis for approval. If the project includes pipelines or onshore terminals, a separate plan for installation and operation (PIO) of these must also be submitted and approved.

A PDO/PIO consists of a development plan and an impact assessment. The latter provides an overview of the likely impacts of the project on the environment, fisheries and society otherwise. The report on the impact assessment is sent to all those who may be affected by the project so that they have an opportunity to put forward their views. The process ensures that all relevant arguments for and against the project are known before a decision on development is taken, that the field developments approved are responsible, and that their impacts on other public interests are acceptable. In special cases, the Ministry may exempt licensees from the requirement to submit a PDO/PIO.

The Ministry of Petroleum and Energy has together with the Ministry of Labour and Social Affairs drawn up guidelines for PDOs and PIOs, which explain the legislation further and detail what the authorities expect from developers. The guidelines are also available on the Norwegian Petroleum Directorate's website.

The development and operation phase is further regulated by Chapter 4 of the Petroleum Act and Chapter 4 of the Petroleum Regulations.

OKEA holds a working interest in the following licenses. A license can be renewed when it expires. As long as the license if fulfilling its obligations, the authorities do not normally revoke a licence.

Production licence	License valid too date	Interest [%]
038 D	01.04.2021	70.000000
316	18.06.2030	15.000000
316 B	18.06.2030	15.000000
338 BS	17.12.2029	20.000000
910	02.03.2024	16.667000
914 S	02.03.2020	0.554000

5.1.7 Cessation of petroleum activities

The Petroleum Act requires licensees to submit a decommissioning plan to the Ministry between two and five years before the production licence expires or is relinquished, or use of a petroleum installation will be terminated permanently. A decommissioning plan consists of two parts: an impact assessment and plans for disposing of the installations.

The impact assessment must provide an overview of the possible environmental and other impacts of the shut-down process. The disposal part must contain detailed plans for closing down operations and decommissioning installations in the best possible way.

Cessation of petroleum activities and decommissioning are governed by Chapter 5 of the Petroleum Act and Chapter 6 of the Petroleum Regulations. In addition, Norway is bound by international law and guidelines. In this context, Decision 98/3 under the OSPAR Convention is particularly important to the Norwegian authorities. The decision generally prohibits leaving disused offshore installations in place, with limited exceptions.

5.1.7 Health, safety and environment and prevention of pollution

The actors in the Norwegian petroleum industry are highly professional and take a very cautious approach, and there is broad-based tripartite cooperation between employers, trade unions and the state. The Government's ambition is for Norway's petroleum industry to be a world leader in health, safety and environment work. The legislation that has been adopted sets strict requirements as regards the responsibilities of individual enterprises for risk identification, risk reduction, preparedness and response. Management of major accident risk is required to be an integral part of petroleum activities.

The authorities and the parties in the industry have together developed a tool for measuring trends in risk levels in Norwegian petroleum activities, known as RNNP. The Norwegian Petroleum Directorate publishes annual reports that give a picture of risk trends in the industry as a whole.

Liability for pollution damage is governed by Chapter 7 of the Petroleum Act, which states that licensees are strictly liable for pollution damage, i.e. they are liable regardless of fault.

Chapters 9 and 10 of the Petroleum Act and regulations under the Act govern safety requirements for the industry.

https://www.norskpetroleum.no/en/framework/the-petroleum-act-and-the-licensing-system/

5.1.8 Economic conditions for exploring and developing licenses

The petroleum taxation system is based on the rules for ordinary company taxation and are set out in the Petroleum Taxation Act (Act of 13 June 1975 No. 35 relating to the taxation of subsea petroleum deposits, etc). Because of the extraordinary returns on production of petroleum resources, the oil companies are subject to an additional special tax. In 2017 the ordinary company tax rate was 24 %, and the special tax rate 54 %. In 2018 these tax rates will be adjusted to 23 % and 55% respectively. This gives a marginal tax rate of 78 %.

5.1.8.1 Net profit

In general, only the Company's net profit is taxable. Exemptions, such as royalties, are no longer a part of the tax system. Deductions are allowed for all relevant costs, including costs associated with exploration, research and development, financing, operations and decommissioning.

Consolidation between fields is allowed. This means that losses from one field, or exploration costs, can be written off against the Company's income from operations elsewhere on the Norwegian shelf.

5.1.8.2 Loss carry forward

Companies that do not have any taxable income may carry forward losses and uplift to subsequent years, with interest. These rights follow the ownership interest and may be transferred. Companies may also apply for a refund of the tax value of exploration costs in connection with the tax assessment. These rules are intended to ensure that exploration costs are treated in the same way for tax purposes regardless of whether or not a company is liable to pay tax.

5.1.8.3 Investment based deductions

When the basis for ordinary tax and special tax is calculated, investments are written off using straight-line depreciation over six years from the year the expense was incurred.

To shield normal returns from the special tax, an extra deduction is allowed in the special tax base, called uplift. In 2016 the total uplift was 22 % (5.5 % per year for four years starting with the investment year). As the ordinary tax and special tax rate has been adjusted in recent years, the uplift has been adjusted accordingly to ensure unchanged overall tax burden. In 2017 the uplift was 21,6 % of the investments (5.4 per year). The uplift is reduced to 21,2 % from 2018.

5.1.8.4 Norm pricing

In many instances, petroleum produced by companies operating on the Norwegian continental shelf is sold to affiliated companies. It is important for the Norwegian government revenues that oil and gas sold from Norway is taxed on the basis of market prices. To assess whether the prices agreed by affiliated companies are comparable to those that would have been agreed by two independent parties, the authorities can set norm prices that must be used when calculating taxable income for the tax assessment.

The Petroleum Price Council is responsible for setting norm prices, which it does after collecting information from the companies and holding meetings with them. The norm price system applies to various types and qualities of petroleum. For gas, the actual sales prices are used.

Taxes are calculated on the following basis

Operating income (norm prices)
- Operating expenses
- Linear depreciation for investments (6 years)
- Exploration expenses, R&D and decom.
- Environmental taxes and area fees
- Net financial costs

= **Corporation tax base (23%)**

- Uplift (5,3% of investments for 4 years)

= **Special tax base (55%)**

6. Business overview

The source of the information contained herein is OKEA AS unless otherwise stated. Please also see chapter 10 of this Registration Document.

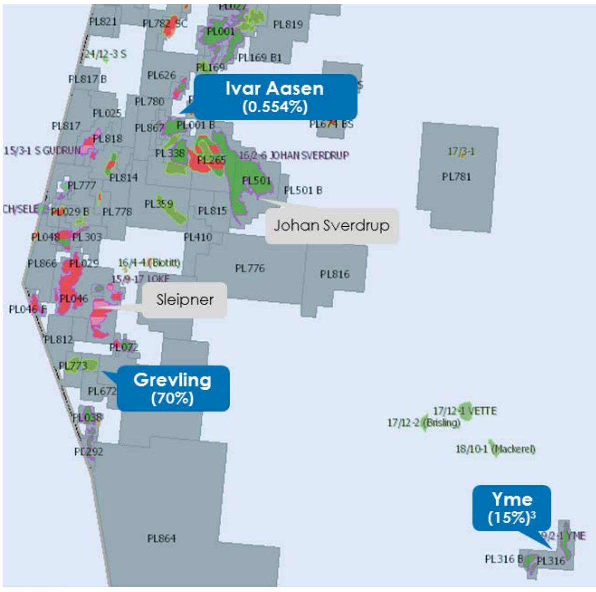
OKEA's focus is on small field developments – the first ever company on the NCS dedicated to this niche. The strategy is to develop small (< 100 mmboe) discoveries and take part in producing assets with value potential. OKEA is dedicated to low cost field developments through; Standardisation, utilising proven and off-the-shelf concepts and existing infrastructure and leased units, reducing capex before 1st oil.

OKEA currently holds a concentrated North Sea portfolio:

- 1 mmboe producing 2P reserves at Ivar Aasen (0.554%) - Entry at USD 4.7/boe
- 10 mmboe 2P reserves under development at Yme (15%) - Entry at USD 0.45/boe
- 20 mmboe 2C resources at Grevling (70%) - Entry at USD 0.01/boe

OKEA total:

- 2P reserves: 11 mmboe
- 2C resources: 20 mmboe



Field/Project	Interest (%)	Operator	Main Resource Class	Comment
Ivar Aasen	0.554%	Aker BP	On production	
Yme field	15 %	Repsol	Justified for development	Main proportion of Okea reserves
Grevling field	70 %	Okea	Development unclarified / on hold	Only contingent resources

Reserves

Reserves are defined as the volume of hydrocarbons that are expected to be produced from known accumulations in production, under development or with development committed. Reserves are also classified according to the associated risks and probability that the reserves will actually be produced. Reserves are classified as 1P, 2P or 3P:

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

Contingent resources

Contingent resources are the volumes of hydrocarbons expected to be produced from known accumulations in planning phase, where development is likely or where development is unlikely with present basic assumptions (e.g. due to the lack of a firm plan of development with the necessary partner or governmental approval, the lack of a market, or the lack of the proper delineation necessary to establish the size of the accumulation for commercial purposes), or under evaluation. Contingent resources are reported as 1C, 2C, and 3C, reflecting similar probabilities as reserves

Ivar Aasen Unit (0,554% working interest, partner)

Discovery and location
Ivar Aasen is a substantial oil field discovered in 2008 and located on the prolific Utsira High, west of the Johan Sverdrup field and about 30 kilometres south of the North Sea Grane field.

Development solution
The field is producing from a steel jacket platform with first stage separation. Final processing takes place on the neighbouring Edvard Grieg platform.

Production, reserves, resources and reservoir
Production from Ivar Aasen started on 24th December 2016.

The 16/1-9 Ivar Aasen reservoir consists of fluvial sandstone in the Skagerrak and Sleipner Formations and shallow marine sandstone in the Hugin Formation, and is of Late Triassic to Middle Jurassic age. The reservoir contains oil at a depth of about 2,400 metres. Parts of the reservoir have an overlying gas cap. The reservoir in 16/1-7 (West Cable) is in fluvial sandstone in the Middle Jurassic Sleipner Formation. It contains oil at a depth of about 2,950 metres. 16/1-9 Ivar Aasen is produced by pressure support from water injection. 16/1-7 (West Cable) is produced by pressure support from an aquifer.[1]

Ivar Aasen net 1P and 2P reserves for 2017:

As of 31.12.2017	Interest	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
		Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
	%	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Reserves – on production											
Ivar Aasen	0.554%	92.2	6.1	17,8	116.1	0.64	122.3	7.6	22.1	152.0	0.84
Total Net oe						0,64					0.84

Ivar Aasen holds an estimated 1 mmboe of 2P reserves net to OKEA, and the field is currently producing approximately 300 boepd net to the Company. Currently, all of OKEA's production comes from the Ivar Aasen field. For Q1 2018 production on the Ivar Aasen field averaged 68,240 boed, of which 380 boed was net to OKEA.

For more technical information regarding Ivar Aasen; volumes, production, status, cut off (see CPR page 19 – table A.2 and A.3) and economic evaluations please see the *AGR Petroleum Services Technical Report* chapter 4 and appendix A. The report is attached to this Registration Document.

Partnership
OKEA holds 0,554% in the Ivar Aasen Unit. OKEA entered the license six months prior to first oil. Other licensees are; Aker BP ASA (Operator) (34.7862%), Equinor Energy AS (41.473%), Spirit Energy Norge AS (12.3173%), Wintershall Norge AS (6.4615%), VNG Norge AS (3.023%) and Lundin Norway AS (1.385 %).

Yme (15% working interest, partner)

Discovery and location
Yme is an oil field in the south-eastern part of the Norwegian sector of the North Sea. It was discovered in 1987. The water depth is 77-93 metres.

[1] Norwegian petroleum - https://www.norskpetroleum.no/en/facts/field/ivar-aasen/

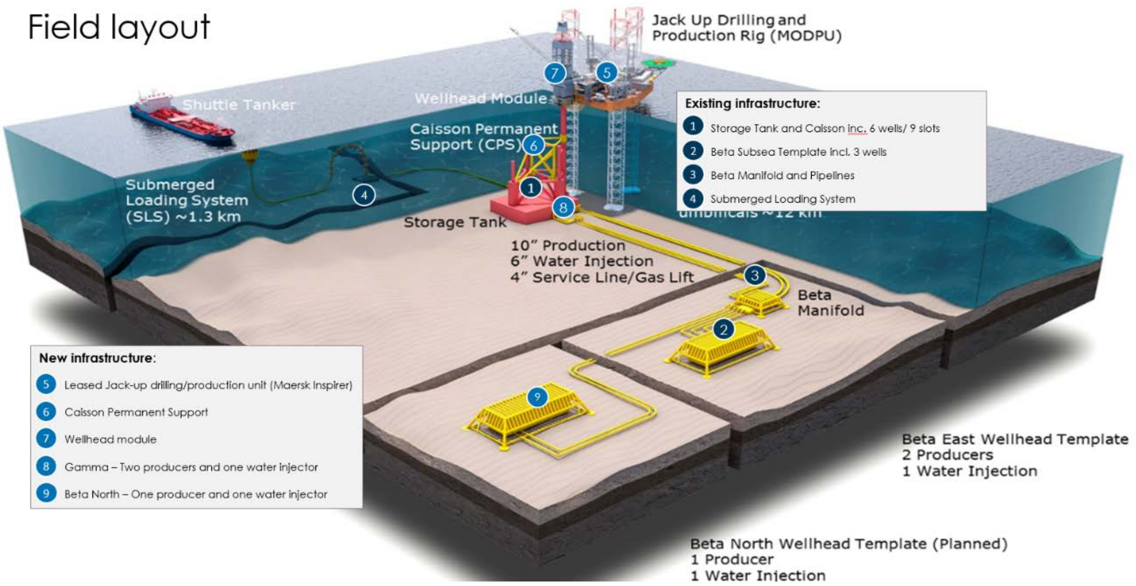
Development solution

Yme was originally developed with a jack-up production platform on Yme Gamma and a storage vessel. The Beta structure was developed with subsea wells. Production started in 1996.

Yme produced 51 mmbbl with Statoil as operator during 1996-2001.

A PDO for redevelopment of Yme was submitted by Talisman in 2007. Due to structural integrity issues with the mobile offshore production unit ("MOPU"), the field was never put in production and the facility was subsequently decommissioned and removed.

In 2015 OKEA launched a development concept based on a leased jack-up rig with production facilities. Throughout 2016 OKEA matured this concept and, on this basis, the license group passed concept selection (DG2) in December 2016. A PDO was submitted on 19th December 2017, and this was approved by Norwegian authorities in March 2018. The project plan has been established to focus on successful delivery of the first oil in the second quarter of 2020, with an internal target of the fourth quarter of 2019.



Production, reserves, resources and reservoir

Yme holds 2P reserves of approximately 65 million barrels of oil. The geology and reservoirs are well known due to extensive well coverage, and five years of production history.

Yme contains two separate main structures, Gamma and Beta. The reservoirs are in sandstone of Middle Jurassic age in the Sandnes Formation, at a depth of about 3,150 metres. [2]

Yme net reserves:

As of 31.12.2017	Interest	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
		Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
	%	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Yme	15%	52.43	0	0	52.43	7.86	64.55	0	0	64.55	9.68
Total Net oe						7.86					9.68

[2] Norwegian petroleum - https://www.norskpetroleum.no/en/facts/field/yme/

For more technical information regarding Yme; volumes, status, cut off (see CPR page 20 – table A.4 and A.5) and economic evaluations please see the *AGR Petroleum Services Technical Report* chapter 4 and appendix A. The report is attached to this Registration Document.

Partnership
OKEA owns 15% of Yme, Repsol Norge AS (operator) 55%, LOTOS Exploration and Production Norge AS 20% and KUFPEC Norge AS 10%. Yme is OKEA's main asset.

Grevling (70% working interest, operator)

Discovery and location
Grevling is an oil discovery located south of the Sleipner field in the southern North Sea. It was discovered in 2009 and appraised in 2010.

Development solution
OKEA is currently evaluating different development solutions for Grevling, based on its low cost philosophy.

Production, reserves, resources and reservoir
Resource estimates are in the range 18-29-50 mmboe (Low-Base-High), not yet matured to a level where investments decisions have been concluded on.

Partnership
OKEA became license operator on 1st of September 2017 and holds a 70% working interest. In 2018, the Company entered into an agreement, with UK independent Chrysaor for the sale of 15% interest in the license. Under the agreement, Chrysaor has an option to acquire an additional 20 percent working interest. The transaction is pending government approval. Petoro AS holds the remaining 30%.

Investments
OKEAs substantial committed investments consists of the Yme development. The commitment is MNOK 489 for 2018, MNOK 406 for 2019 and MNOK 291 for 2020. (Ref. OKEA annual report 2017, note 10).

In November 2017 the Company entered into a secured bond loan of USD 120 million. The bond loan, with maturity in 2020 will fund these investments, together with operating income from Yme, once in production.

In June 2018, OKEA announced it has entered into an agreement with A/S Norske Shell to acquire working interests in the Draugen (44.56% - Operator) and Gjøa (12% - Non-operator) fields for a total consideration of 4.52 billion NOK (~$556 million). 80% of decommissioning financial liabilities will remain with Shell up to an agreed cap.

Field name	Licence no.	Acquired working interest
Draugen	PL093, PL093B, PL093C, PL093D, PL158 and PL176	44.56%
Gjøa	PL153, PL153B and PL153C	12%

The transaction will be financed through a combination of underwritten bond loan and equity. Bangchak Corporation PCL, a Thai downstream oil and gas company, have entered into a strategic partnership with Seacrest Capital Group, and together they will finance the acquisition.

The deal is subject to government approvals, with completion expected by Q4 2018 and the effective date for the transaction January 1st 2018.

For more information regarding the transaction, please see the stock exchange announcements 20th June 2018 - https://newsweb.oslobors.no/search?category=&issuer=&fromDate=2018-06-20&to-Date=2018-06-20&market=&messageTitle=okea

Market

OKEA produces and sell hydrocarbons in the form of oil and gas.

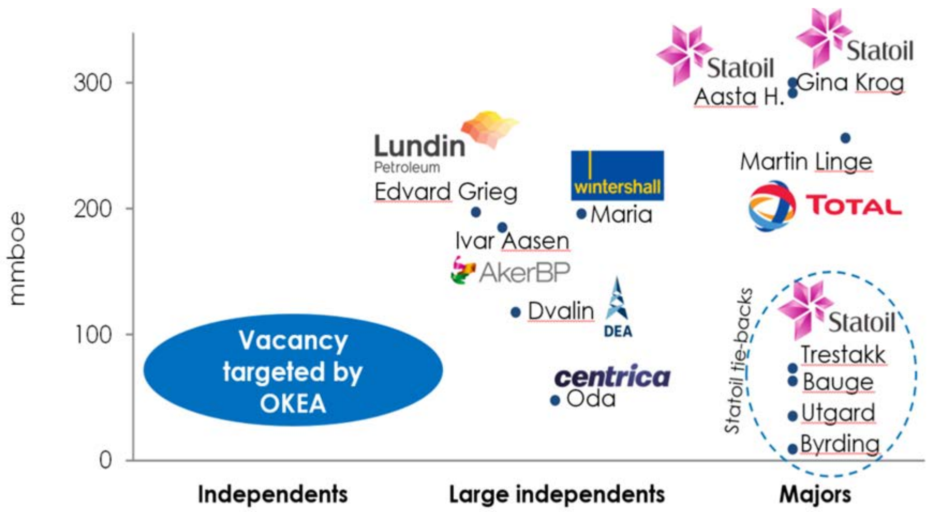
The oil market is global with prices set on a continuous basis in international financial markets. OKEA is selling its products to Shell at terminal. The Company do not participate in the downstream part of the value chain, that is refining and trading.

The gas market is more local than the oil market as the product is more difficult to ship than oil. Gas produced by OKEA is exported to the UK, through the SAGE pipeline and sold to Hartree at beach in the UK. OKEA do not participate in the downstream part of the gas value chain.

Substantial exploration activity during the last decade has resulted in a large number of undeveloped discoveries. Sub 100 mmboe discoveries are generally not of interest to the majors and hence available at attractive prices and can often be acquired at prices below exploration cost. Ongoing and future exploration will inevitably further add to the inventory of such discoveries.

OKEA will strategically focus on becoming the leading operator for cost effective developments below 100 mmboe. Lack of willing and capable independent operators leads to less sub 100 mmboe field developments on the NCS than in GoM and UK. Limited focus on sub 100 mmboe stand alone fields due to lack of scale for the current operators – leaves a large vacancy that can be filled by OKEA.

Developments by size and operator type



** Statoil ASA changed the company name to Equinor ASA from 16.05.2018*

Standalone developments are typically more than 100-150 mmboe and operated by a small group of majors and large independents. Operators that have left or merged with other players on NCS since 2015: BG, BP, Dana, EnQuest, EoN, Marathon, Noreco, Premier, Rocksource, Spike, Svenska Petroleum, Talisman and Tullow.

7. Administrative, management and supervisory bodies

Board of Directors:

Name	Position
Henrik Schröder	Chairman
Kaare Gisvold	Board member
Paul Anthony Murray	Board member
Knud Nørve	Board member
Arild Selvig	Board member

Management:

Name	Position
Erik Haugane	CEO
Knut Evensen	CFO
Ola Borten Moe	CCO
Anton Tronstad	COO
Dag Eggan	SVP HSE

Set out below are brief biographies of the members of the Board of Directors and Management of the Issuer in alphabetical order:

Anton Tronstad – Chief Operating Officer
Mr. Tronstad has thirty years' experience at Kværner and Statoil. SVP Drilling at Pertra. He was the co-founder and SVP of Drilling at Det Norske oljeselskap. He holds a Master of science in Mechanical Engineering.

Arild Christian Selvig – Board member
Mr. Selvig is the Vice President BD & Tendering Subsea Projects in TechnipFMC. 30 years' experience within O&G management from amongst other Norsk Hydro and FMC. Board experience from Norwegian Oil & Gas Supplier Association, Norwegian Petroleum Society, FMC Eurasia and ONS Foundation. Ha has been a board member in OKEA since 2018.

Dag Eggan – Senior Vice President Health and Safety Environment
Mr. Eggan was co-founder and partner of PIER Offshore Management Services. He has experience from several senior management positions, including Quality Risk Manager in the Mobile Newbuilds (MNB) Group in Statoil ASA and VP QSHE in Ocean Rig, Sevan Drilling and Skeie Drilling & Production AS.

Erik Haugane – Chief Executive Officer
Mr. Haugane was the founder of Pertra (2001) and co-founder of Det Norske oljeselskap (2005). He also has several years in PGS and NOPEC, among other a period in Singapore. He is a recipient of Norwegian Petroleum Society's honorary award. He holds a Cand. Real. degree in Exogene Geology from the University of Tromsø.

Henrik Schröder – Chairman of the Board
Mr. Schröder is co-founder and Partner for Seacrest Capital Group. He has 30 years in international finance, management and business development including president of Saab Aircraft, co-founder of Sven Hagströmer Företagsfinansiering and private investor in E&P sector, early investor in RXT and co-founder and Chairman of Enovation Resources Ltd. Ha has been the Chairman of the Board in OKEA since inception of OKEA in 2015.

Knud Hans Nørve - Board member

Mr. Nørve is the CEO Infragas Norge AS. 30 years experience within O&G management and financial analysis from amongst other Norsk Hydro, Fortum Petroleum, Econ Analysis and Rystad Energy. Board experience from Misen Energy AB and P/F Atlantic Petroleum. He has been a board member in OKEA since 2018.

Knut Evensen – Chief Financial Officer

Mr. Evensen is former VP Business Development and Acting CFO at Det Norske oljeselskap. Analyst at Pareto and Danske Market. He holds a Master of science in Business Administration and is a Certified Financial Analyst from Norwegian school of Management (NHH).

Kaare Moursund Gisvold – Board member

Mr. Gisvold is an independent consultant, investor, director and advisor to various businesses. Extensive O&G senior management and board experience from companies like Golar Nor (now Teekey), PGS, Pertra and Det norske oljeselskap ASA. Ha has been a board member in OKEA since 2018.

Ola Borten Moe – Chief Commercial Officer

Mr. Borten Moe is the former Norwegian Minister of Petroleum and Energy and former Norwegian Member of Parliament. He is a recipient of Norwegian Petroleum Society's honorary award. He holds a Bachelor of science in Agriculture Management.

Paul Anthony Murray - Board member

Mr. Murray is co-founder and Partner of Seacrest Capital Group. 20 years in technology and growth capital investment, fund management including Investment Director at 3i and Cazenove Private Equity and Founder and Managing Partner of DFJ Esprit, a $1bn+ multi fund investment firm. He has been a board member in OKEA since inception of OKEA in 2015.

All the members of the board of directors and management can be reached at the Company's business address; Ferjemannsveien 10, N-7042 Trondheim, Norway.

There are currently no potential conflicts of interests between any duties to the Issuer of the persons referred to in this section and their private interests or other duties.

Corporate governance

The Company is not a listed company and therefore is not required to comply with the Norwegian Code of Practice for Corporate Governance.

Nomination committee

The Company has not established a nomination committee.

Remuneration committee

The Company has not established a remuneration committee.

Audit committee

The Company has not established an audit committee in accordance with Section 6-41 (2) of the Public Limited Liability Companies Act.

8. Major shareholders

OKEA AS's share capital is NOK 3,715,144 divided into 3,715,144 shares with each share having a par value of NOK 1, fully paid. There is only one class of shares and there are no differences in voting rights between the shares.

Holdings				
Ranking	Holding	Percentage	ISIN	Name
1	2 875 000	77.38596 %	NO0010816895	OKEA Holdings Ltd.
2	111 730	3.00742 %	NO0010816895	SPAREBANK 1 SMN INVEST AS
3	82 134	2.21079 %	NO0010816895	KØRVEN AS
4	81 857	2.20333 %	NO0010816895	SJÆKERHATTEN AS
5	56 000	1.50734 %	NO0010816895	FORTE TRØNDER
6	54 539	1.46802 %	NO0010816895	SKJEFSTAD VESTRE AS
7	53 139	1.43033 %	NO0010816895	KEBS AS
8	50 000	1.34584 %	NO0010816895	JENSSEN & CO A/S
9	44 693	1.20300 %	NO0010816895	LIGNA AS
10	20 000	0.53834 %	NO0010816895	JOHAN VINJE AS
11	16 760	0.45113 %	NO0010816895	Bernhd. Brekke A/S
12	16 759	0.45110 %	NO0010816895	HOLMETJERN INVEST AS
13	16 750	0.45086 %	NO0010816895	TRIPPEL-L AS
14	15 319	0.41234 %	NO0010816895	365 FRI AS
15	13 618	0.36655 %	NO0010816895	LYCKLIGA GATAN AS
16	12 000	0.32300 %	NO0010816895	UNIQUM AS
17	11 200	0.30147 %	NO0010816895	WIST HOLDING AS
18	11 175	0.30080 %	NO0010816895	JARAS INVEST AS
19	11 174	0.30077 %	NO0010816895	VINTERVEIEN EIENDOM AS
20	11 173	0.30074 %	NO0010816895	LYNG GRUPPEN AS

OKEA Holding Ltd. owns 77.34 % of the Issuer and has direct control over the Company. OKEA is a subsidiary to OKEA Holding Ltd. as the major shareholder. OKEA Holding Ltd is owned by Seacrest Capital, an international private equity manager that invests in the global offshore oil and gas exploration and production industry. There is a signed shareholder agreement between all shareholders of the Company that governs the ownership of the Company. There are no measures in place to ensure that such control is not abused.

According to the shareholder agreement, key employees may be given up to 125.000 warrants which are subject to certain key objectives to be met. One warrant equal one share at the subscription price NOK 179, -.

As at the date of this Registration Document, there are no arrangements known to the Issuer which may at a subsequent date result in a change in control of the Issuer.

9. Financial information

The Company meets the ESMA definition of SME for the last financial year by having in 2017 less than 250 employees and revenue below EUR 50 000 000. The Company's financial statements for 2017 are prepared in accordance with the accounting principles prescribed by International Financial Reporting Standards (IFRS) as adopted by the European Union. The interim accounts have been prepared in accordance with IAS 34 Interim Financial Reporting. The financial information set out below is derived from these reports and are attached to the Registration Document:

OKEA AS *Amounts in NOK '000*	**31 Dec 2017** audited	**Q1 2018** unaudited	**Q1 2017** unaudited
INCOME STATEMENT			
Revenue from crude oil and gas sales	38 429	2 314	872
Total operating expenses	-99 223	-34 833	-21 624
Profit/loss from operating activites	-55 788	-18 498	-13 527
Net financial items	-24 709	5 197	-1 260
Profit/loss before income tax	-80 494	-13 301	-14 788
Net profit / loss for the period	**-11 714**	**-486**	**-2 709**
BALANCE SHEET			
Total non-current assets	775 495	829 219	629 815
Total current assets	1 057 615	1 112 946	126 634
Total Assets	**1 833 110**	**1 942 165**	**756 449**
Total equity	473 827	577 711	361 767
Total non-current liabilities	1 282 979	1 239 259	203 966
Total current liabilities	76 304	125 195	190 716
Total equity and liabilities	**1 833 110**	**1 942 165**	**756 449**
CASH FLOW STATEMENT			
Net cash flow from operating activities	-37 278	-13 966	-7 199
Net cash flow from investing activities	-1 031 897	1 800	-66 580
Net cash flow from financing activities	1 060 895	103 787	53 308
Net change in cash and cash equivalents	-8 280	91 621	-20 471
Cash and cash equivalents at the end of the period	**29 609**	**121 230**	**17 418**
Restricted and unrestricted cash at the end of the period	**937 408**	**980 862**	**17 418**

The Company's historical financial information for 2017 has been audited. The audit report is attached to this Registration Document. The interim accounts are unaudited.

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Issuer is aware of), during a period covering at least the previous 12 months which may have, or have had in the recent past, significant effects on the Issuer's financial position or profitability.

Other than the reference to the information mentioned under "Investments" in chapter 6 ("*Business overview*") and that the Company in May 2018, established a NOK 300m exploration facility with SEB and Sparebank1 SMN, there is no significant change in the financial or trading position of the Issuer which has occurred since the end of the last financial period for which either audited financial information or interim financial information have been published. Furthermore, there has been no material adverse change in the prospects of the Issuer since the date of their last published audited financial statements, and there are no known trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Issuer's prospects.

The Issuer affirms that no material changes have occurred since the date of the competent person's report.

There are no recent events particular to the Issuer that are to a material extent relevant to the evaluation of the Issuer's solvency.

There are no material contracts that are not entered into in the ordinary course of the Issuer's business, which could result in any Company member being under an obligation or entitlement that is material to the Issuer's ability to meet its obligation to security holders in respect of the securities being issued.

10. Third party information and statement by experts and declarations of any interest

If not otherwise stated, the source of the information contained is the Registration Document is OKEA AS and its management.

Some information contained in chapter 6 "*Business overview*" are from www.norwegianpetroleum.no. This site is run in cooperation by the Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate. This information has been sourced from a third party and has been accurately reproduced an as far as the Company is aware and able to ascertain from information published by such third party, no facts have been omitted which would render the reproduced information inaccurate or misleading. The illustrations in this chapter are from the Company's investor presentation in connection with the bond issue with ISIN NO0010810062 - not publicly available.

The resource estimates regarding Grevling in chapter 6 "Business overview" are OKEA's own estimates.

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

The evaluation (shown in Appendix 1) was managed by Erik Lorange (MSc in Geology), AGR Exploration Manager. Mr. Lorange, a Geologist, has 30+ years of international and Norway experience. The report was reviewed and excepted by Morten Heir (MSc in Petroleum Engineering and MBA), AGR Vice President Reservoir Management. Mr. Heir has 25+ years of international experience, including the North Sea. AGR has conducted valuations for many energy companies and financial institutions. AGR confirms that the Competent Persons Report can be used in connection with this Registration Document.

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

11. Documents on display

For the life of the Registration Document the following documents (or copies thereof) may be inspected:

- The Company's articles of association.
- The audited 2017 annual financial statements of the Issuer (IFRS).
- The unaudited Q1 2018 report
- AGR Petroleum Services Technical Report

The documents may be inspected at the Company's registered office, Ferjemannsveien 10, N-7042 Trondheim, Norway, during normal business hours from Monday to Friday each week (except public holidays).

12. Attachments

1. AGR Petroleum Services Technical Report
2. OKEA AS - Annual report 2017
3. The 2017 audit report
4. OKEA AS – Q1 2018

AGR Petroleum Services

Reservoir Management Division

Oslo

Reserves Certification 31.12.2017

Final

For OKEA AS
May 2018

AGR Petroleum Services
Technical Report

Reserves Certification 31.12.2017
Final

Approval			
	Name	*Position*	*Date*
Prepared by:	Erik Lorange Anna Lena Hellman Marte Herud Birger Heidenstrøm Per Atle Flytlie Wiggo Moen	Project Leader Geologist Res. Eng. and economy Reservoir Engineer Drilling and Wells Facilities	31.05.2018
Reviewed and Accepted By:	Morten Heir M. He	VP Reservoir Management	31.05.2018

Document Control			
Copy No.:	1	*Issued to:*	OKEA AS
File:	OKEA Reserves Certification_31.12.2017.pdf		
Rev. No.	*Date*	*Modification Details*	
01	18.05.2018	DRAFT	
02	24.05.2018	FINAL	
03	31.05.2018	FINAL, short version	

Qualifications

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

The evaluation was managed by Erik Lorange (MSc in Geology), AGR Exploration Manager. Mr. Lorange, a Geologist, has 30+ years of international and Norway experience. The report was reviewed and excepted by Morten Heir (MSc in Petroleum Engineering and MBA), AGR Vice President Reservoir Management. Mr. Heir has 25+ years of international experience, including the North Sea. AGR has conducted valuations for many energy companies and financial institutions.

Evaluation Standard

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

Basis of Opinion

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

Disclaimer

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

Table of Contents

List of Figures

List of Tables

1 Summary and conclusions

AGR has conducted a reserves certification of two assets for OKEA AS in accordance to the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE.

The reserves are estimated as of 31.12.2017.

A discounted cash-flow model with an oil price of 60.0 USD/bbl has been used to determine the economic life for low and medium case, and hence the net 1P and 2P reserves attributable to OKEA.

The following OKEA reserves are endorsed by AGR and listed in Table 1.1

Table 1.1 Net OKEA reserves as of 31.12.2017 according to PRMS

Asset/ Operator	OKEA interest (%)	1P (MSm³ o.e.)	2P (MSm³ o.e.)	1P (mmboe)	2P (mmboe)	Classification	Certification
Ivar Aasen / Aker BP	0.554	0.10	0.13	0.62	0.84	Reserves	First time
Yme / Repsol	15.0	1.25	1.54	7.87	9.68	Reserves	First time
Total		**1.35**	**1.67**	**8.48**	**10.53**		

2 Introduction and objectives

AGR has conducted a reserves certification of OKEA AS reserves in accordance to the Petroleum Resources Management System (PRMS) of SPE/WPC/AAPG/SPEE.

This report covers first time certification of 1P and 2P reserves of the following assets (see Fig. 2.1 and Fig. 2.2 for locations):

- Ivar Aasen (Aker BP is the Operator and OKEA owns a 0.554 % share)
- Yme (Repsol is the Operator and OKEA owns a 15.0 % share)

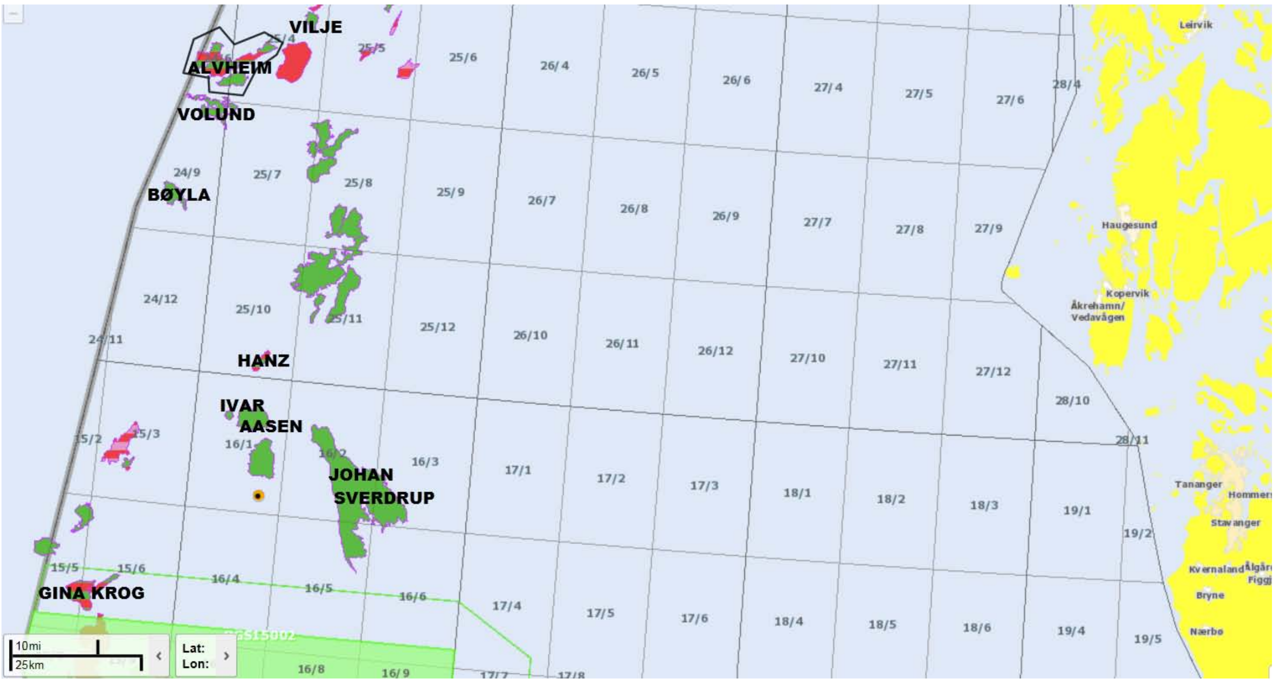


Fig. 2.1 Location of the Ivar Aasen field in the North Sea.

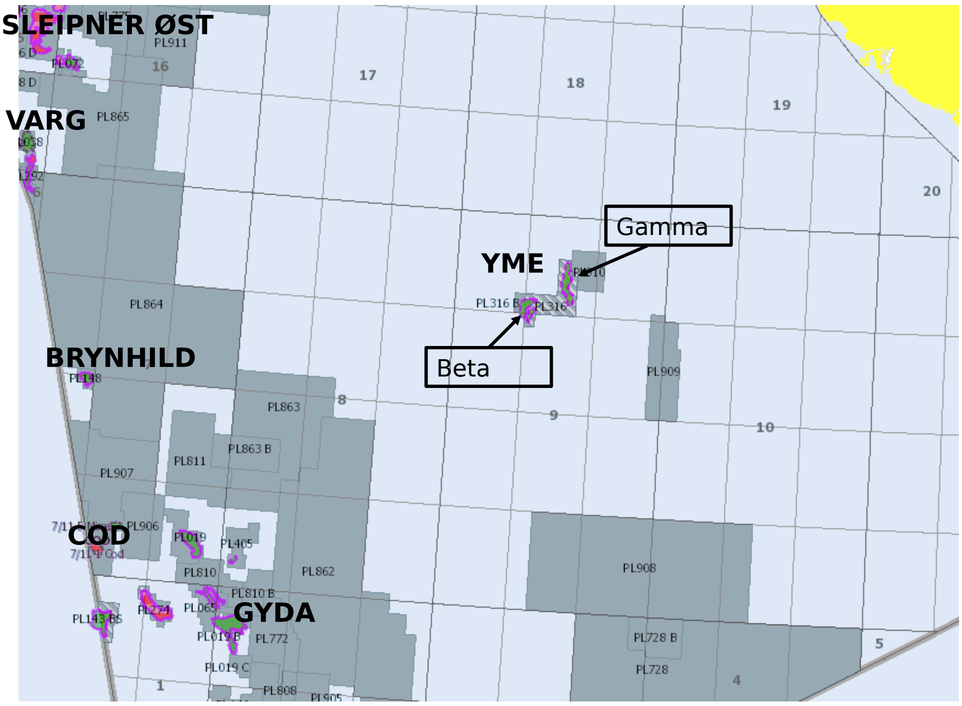


Fig. 2.2 Location of the Yme field in the North Sea.

All production profiles, reserves, and in-place volumes received from OKEA and certified by AGR, are expressed in SI units (Sm3). The combined hydrocarbon reserves (oil equivalents) are also expressed in mmboe. The oil price is quoted in USD/bbl and the cost profiles are reported in MNOK (million Norwegian Kroner).

Whenever the term "technical" is used with production volumes or profiles, it refers to the estimates before the economic evaluation, i.e. before an economic cut-off has been applied to determine reserves.

3 Methodology

The methodology applied in this report was (assuming relevant data/information was available):

- Review of the available data, interpretations and resulting models and reports.
- The critical parameters were checked in terms of origin of the data, the interpretation and application thereof.
- Review of uncertainty evaluations and how key uncertainties impact the project.
- Review and analysis of the Petrel™ and Eclipse™ models. However, no new modelling has been performed except using existing models to enhance understanding and to verify results.
- Review the costs and economic models.
- Determine economic cut-offs with resulting reserves.
- Classify the reserves according to the PRMS (SPE/WPC/AAPG/SPEE). This classification system recommends that no reserves are booked beyond licence expiry date. However, it is a common practice on the Norwegian Continental Shelf that licence period extensions are granted. It is, therefore, assumed that licence periods will be extended and reserves may be recovered beyond the existing licence expiry dates.
- For all the assets the RNB2018 submission is the basis for the reserves and cost profiles to be certified. The RNB low case is assumed to represent the P90 case, and the base case is assumed to be close to and practically equal to the P50 case.
- The gas reserves are reported as sales gas given the actual Gross Calorific Value (GCV) and not converted to 40 MJ/Sm^3.
- RF in this report is defined as the reserves divided by initially in place. Note that with this definition gas recovery factor may not represent the actual recovery of gas from the field.
- The 2017 produced volumes reported herein are based on actual production from January through September 2017 and forecast for remaining three months. These volumes are used for assessment of remaining reserves as of 31.12.2017 (this is in accordance with RNB 2018).

Conversion factors
The following conversion factors are applied in the report:

- Oil and condensate
    - 1 Sm^3 = 6.29 bbl
    - 1 Sm^3 = 1 Sm^3 o.e.
- Gas
    - 1000 Sm^3 gas = 1 Sm^3 o.e.
- NGL
    - 1 tonne NGL = 1.9 Sm^3 o.e.
    - 1 Sm^3 o.e. = 6.29 boe

4 Certification

4.1 Ivar Aasen

Asset overview
The Ivar Aasen field is located in block 16/1 in the North Sea, 8 km north of the Edward Grieg field, and around 30 km south of Grane and Balder. The field contains both oil and free gas. The Ivar Aasen field includes two accumulations; Ivar Aasen and West Cable (Fig. 4.1). The accumulations cover several licences and have been unitized into the Ivar Aasen Unit (Table 4.1). Ivar Aasen commenced production 24.12.2016. The water depth in the area is approximately 110 m and the main reservoir in Ivar Aasen is found at about 2400 m TVD MSL.

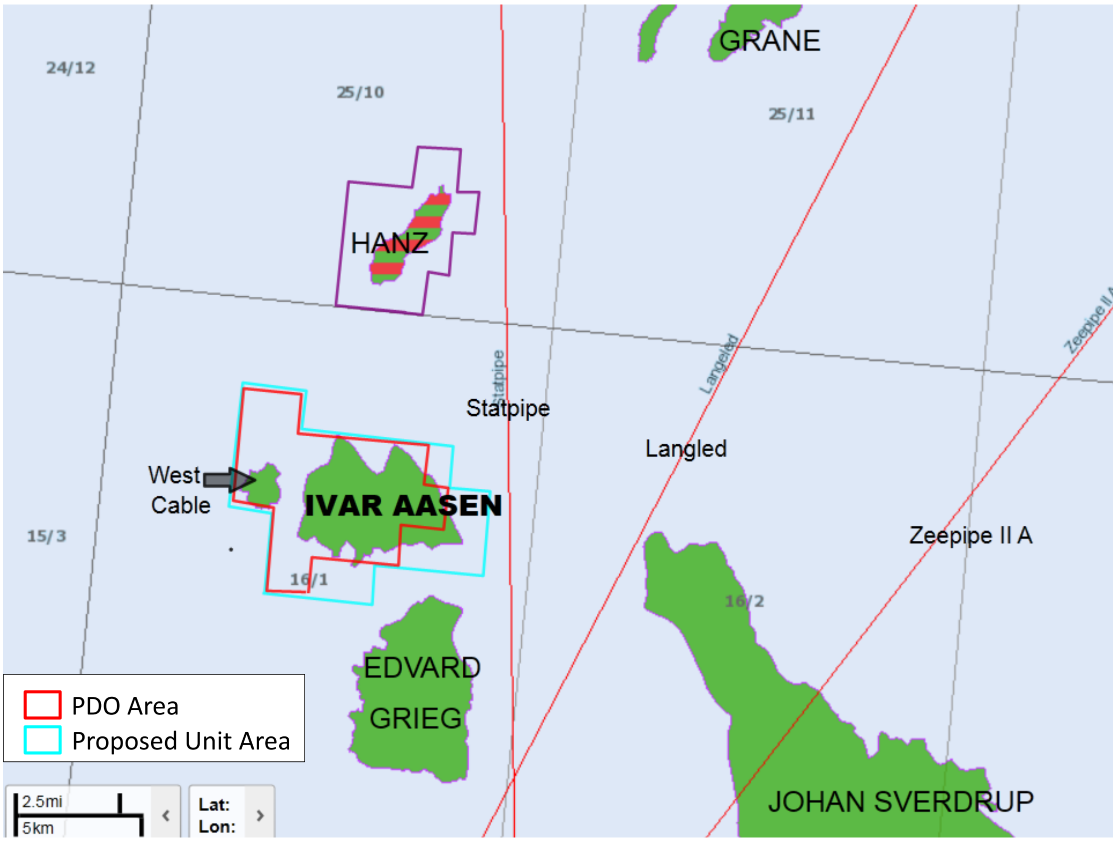


Fig. 4.1 Ivar Aasen Field location map
Unit boundaries are shown.

Table 4.1 Ivar Aasen field licence shares (%). The field cover PL001B, PL242, PL457 and PL338BS.

Licence	Statoil	Aker BP (Op.)	Spirit Energy	Wintershall	VNG	Lundin	OKEA
Ivar Aasen	41.4730	34.7862	12.3173	6.4615	3.0230	1.3850	0.5540

Discovery
Ivar Aasen was discovered with well 16/1-9 in 2008, proving oil and gas in Jurassic and Triassic sandstones. An earlier exploration well 16/1-2 in 1976 within the structural closure was initially classified as dry, but was after a re-examination re-classified as an oil discovery. West Cable was discovered with well 16/1-7 in 2004, proving oil in Jurassic sandstones.

Reservoir
The two accumulations are located at the Gudrun Terrace between the southern Viking Graben and the Utsira High. The reservoir sands are fluvial and shallow marine deposits of late Triassic to late Jurassic age. The reservoir sands in the Ivar Aasen structure are complex and heterogeneous while the reservoir at West Cable is more homogeneous. The Ivar Aasen structure contains saturated oil and a small gas cap, while the West Cable structure contains undersaturated oil.

Development
The drainage strategy for the Ivar Aasen structure is water injection for pressure maintenance. West Cable will be produced by natural depletion, where the major driving force is aquifer drive. In total seven producers (six targeting the Ivar Aasen structure and one in West Cable) and six water injectors (in the Ivar Aasen structure) have been drilled in the Ivar Aasen field. The horizontal production wells are completed with mechanical sand control and ICD completions while the vertical injectors have cemented perforated liners. In Phase 2 (Q4 2021) of the development, the Hanz discovery will be developed with two subsea wells tied-back to the Ivar Aasen platform. Hanz is not part of this audit as OKEA has no stake in the reservoir.

The field is developed with a PDQ (production, Drilling and living Quarter) platform at a water dept of 110 m, and includes living quarters and process facilities with dry well heads on the platform. The wells are drilled from a jack-up rig. The well stream is partly processed on the platform before transportation through pipelines to the Edvard Grieg installation for final stabilization and export. Edward Grieg also covers Ivar Aasen power demand until a joint solution for power from shore is established.

Status
All initially planned wells have been drilled in the Ivar Aasen (6OP+6WI) and West Cable (1OP) structures. The development wells on Ivar Aasen main field came in roughly as expected. The first development well in West Cable was disappointing as top reservoir came in deeper than expected. The side track on West Cable was successful with penetration of oil filled reservoir sands. West Cable holds only 13 % of the PDO in place volume.

The production of Ivar Aasen has been as expected for 2017, and the field is producing with good efficiency (total uptime of 90 % in 2017). However, the field is experiencing depletion. Eastern part of the field is depleted 50 bars to initial pressure (248 bars) whilst it is reduced approximately 20 bars in the west (March 2018). The reason for this is:

- Water injection challenges. The injection challenges has been partly due to completion leakages (now repaired) and partly due to lower injectivity in Skagerrak 2 than expected. The operator will mitigate this by drilling two new injection wells in Q2 2018. The vertical D7 water injector will inject into the Statfjord, Sleipner and Hugin formations, and secure 0.69 MSm3 of oil equivalents (3.5 % of total reserves). The well is needed to be able to produce at an oil rate of 9000 - 9500 Sm3/sd in 2018, according to the Operator. The horizontal injector D6 will inject into the Skagerak 2 formation.
- Higher oil production and GOR than expected. Free gas production in the west represents about 50% of the produced reservoir volume.
- Delayed start-up of injection
- Lower regularity of the water injection system than planned

To reduce the depletion, oil production was reduced down from 9 400 to 9 000 Sm3/d in mid December 2017. This slowed down the depletion in the east from 3.0 to 2.5 bar/month. The two new injectors in the east will slow down the depletion, but will probably not be enough to stop it. Continued use of high pressure pumps in D-4 and later D-3 is therefore necessary, as well as increasing the injection rate in the other injectors. It may also be necessary to drill another injector in 2019 to stop the pressure declining.

In general the Ivar Aasen main field has proven larger and better than in the PDO. However, the reserves on West Cable has been reduced significantly.

The recoverable volumes of Ivar Assen are classified as "Reserves; On Production" (SPE's classification system).

Volumes presented by OKEA
The Initially In-Place Volumes (IIPV) estimates as of 31.12.2017 are given in the RNB2018, and are listed in the table below.

Table 4.2 IIPV for Ivar Aasen. The numbers include Ivar Aasen and West Cable, but exclude "Alluvial Fan"(Exploration discovery 16/1-22A in 2015).

	IIPV, 31.12.2017	
	Low	**Base**
Oil/condensate, MSm^3	35.58	44.48
Gas, GSm^3	7.44	9.38

<u>AGR comments to IIPV</u>

- *General*
  - The numbers in Table 4.2 includes Ivar Aasen main field and West Cable. Alluvial fan in Ivar Aasen and West Cable East are excluded.
    - The IIPV as of 31.12.2017 are from RNB2018 submission for Ivar Aasen main field. The IIPV for oil on West Cable has been reduced according to the updated model after drilling, but IIPV for associated gas is too high in RNB2018, and have not been changed accordingly. Adjustment using GOR from RNB2017 will reduce P90 to 7.0 and P50 to 8.8 GSm3.
    - The development wells on Ivar Aasen main field mainly came in as expected on Ivar Aasen. Updating of geomodels are ongoing, and preliminary results from the development wells are included, except for the latest producer D-12. The latest model estimates slightly lower IIPV than the reported P50, but on the other hand history match indicates higher STOIIP in two producer areas (D-19 and D-5).
    - P90 value for Ivar Aasen main field is assumed to be equal to the P50 less 20 %, where the 20 % range is similar to the range used in the Reservoir Management Plan (RMP) 2014 study. AGR is of the opinion that the +/- 20 % range is reasonable, but expects that a future uncertainty analysis will narrow the range as the field now has good well coverage.
- *Conclusion*
  - In AGR's opinion the IIPV figures are reasonable.

Table 4.3 shows the net 1P and 2P reserves for the Ivar Aasen field, as presented by OKEA. The 3P reserves are not a part of this audit, and therefore not presented.

Table 4.3 Ivar Aasen net 1P and 2P reserves for 2017 (0.5540 %)
Reserves 31.12.2017, as presented by OKEA

As of 31.12.2017	Interest	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
		Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
	%	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Reserves – on production											
Ivar Aasen	0.554%	92.2	6.1	17,8	116.1	0.64	122.3	7.6	22.1	152.0	0.84
Total Net oe						0,64					0.84

<u>AGR comments to reserves</u>

- *General*
  - The reserves as of 31.12.2017 are consistent with those of RNB 2018.
  - The reserves reported by the Operator are based on a history matched simulation model up to 11th of October 2017. The two new water injectors, D-6 and D-7, assumed starting Q2 2018, are included in this simulation.
  - The Ivar Aasen reserves are a combined contribution from the Ivar Aasen main field and the West Cable structure. The reserves from West Cable constitutes less than 0.5 % of the total reserves from the unit.
  - The net total reserves as reported by OKEA, corresponds to saleable gas of 40 MJ/Sm^3.
- *Conclusion*
  - The 1P oil volume is 22 % less than the 2P oil reserves. At first sight this may appear somewhat optimistic considering the current challenges with water injection and high GOR. Having said that, the decision has been made for two more water injectors in 2018 which we consider being a robust mitigation for assuring the 1P reserve estimate.

- The P50 recovery factor at EUR shown in Table 4.5 is reasonable when compared to NCS fields with similar drainage strategies.
- AGR endorse both the 1P and 2P reserves.

Reserves certified by AGR
Economic evaluations have been carried out for the Ivar Aasen field based on the costs and production profiles originally supplied by OKEA and reviewed by AGR.

The economic evaluations have confirmed that the P50 is economically robust under the base oil price. The economic cut-off is reached at the end of technical production profiles for P50. P90 has an economic cut-off 5 years earlier than technical production profile. The key results are summarised below. As can be seen the certified 1P reserves is 0.62 mmboe as compared to the OKEA estimate of 0.64 mmboe as reported in Table 4.3. The reason for this is that AGR has applied an economic cut off in year 2030 for the low case. More details on the estimation of the economic cut-offs together with the production profiles are given in Section A.1 Ivar Aasen Economic Summary and Production Profiles.

Table 4.4 Net Ivar Aasen reserves as of 31.12.2017

Reserves	1P	2P
Oil/condensate, MSm^3	0.08	0.11
Gas, GSm^3	0.02	0.02
NGL, MSm^3 o.e.	0.01	0.01
Total, MSm^3 o.e.	**0.10**	**0.13**
Total, mmboe	**0.62**	**0.84**

The above reserves are based on sound industry practice and are endorsed.

Table 4.5 Ivar Aasen recovery factors

	Oil RF by end 2017	Oil RF at EUR	Gas RF by end 2017	Gas RF at EUR
Ivar Aasen	5 %	49 %	8 %	51 %

Recovery factor on West Cable is 24 % at EUR.

References
The main references provided were:

- Ivar Aasen_ RNB2018.xlsm, OKEA
- Ivar Aasen_ RNB2017.xlsm, OKEA
- Ivar Aasen LRP 2018.pdf, OKEA.
- Ivar Aasen PUD.pdf, OKEA
- Reservoir Comity meeting_21.11.17_post meeting handout.pdf, OKEA
- Reservoir Management Plan - 2018.pdf, OKEA
- OKEA AS, Annual Statement of Reserves 2018
- Various power points supplied by OKEA
- Answers to Q&A.

4.2 Yme

Asset Overview

The Yme field is located 160 km north-east of the Ekofisk field, see Fig. 4.2, in water depth of 93 meters in the Norwegian Danish Basin. It was discovered by Statoil in 1987 and was put on production in 1996. Yme ceased production in 2001 after having produced 8.1 MSm^{3}oe (51 mmboe) as operation was no longer profitable. However, there were significant volumes left in the field, and in 2007 a redevelopment plan submitted by the new operator, Talisman, was approved. In 2013, after drilling 9 new development wells and 2 appraisal wells, the redevelopment project was abandoned due to structural deficiencies in the mobile offshore production unit. In 2015 "Yme New Development", was initiated, and in December 2017 a PDO for this development was submitted to the authorities with first oil planned for 2020.

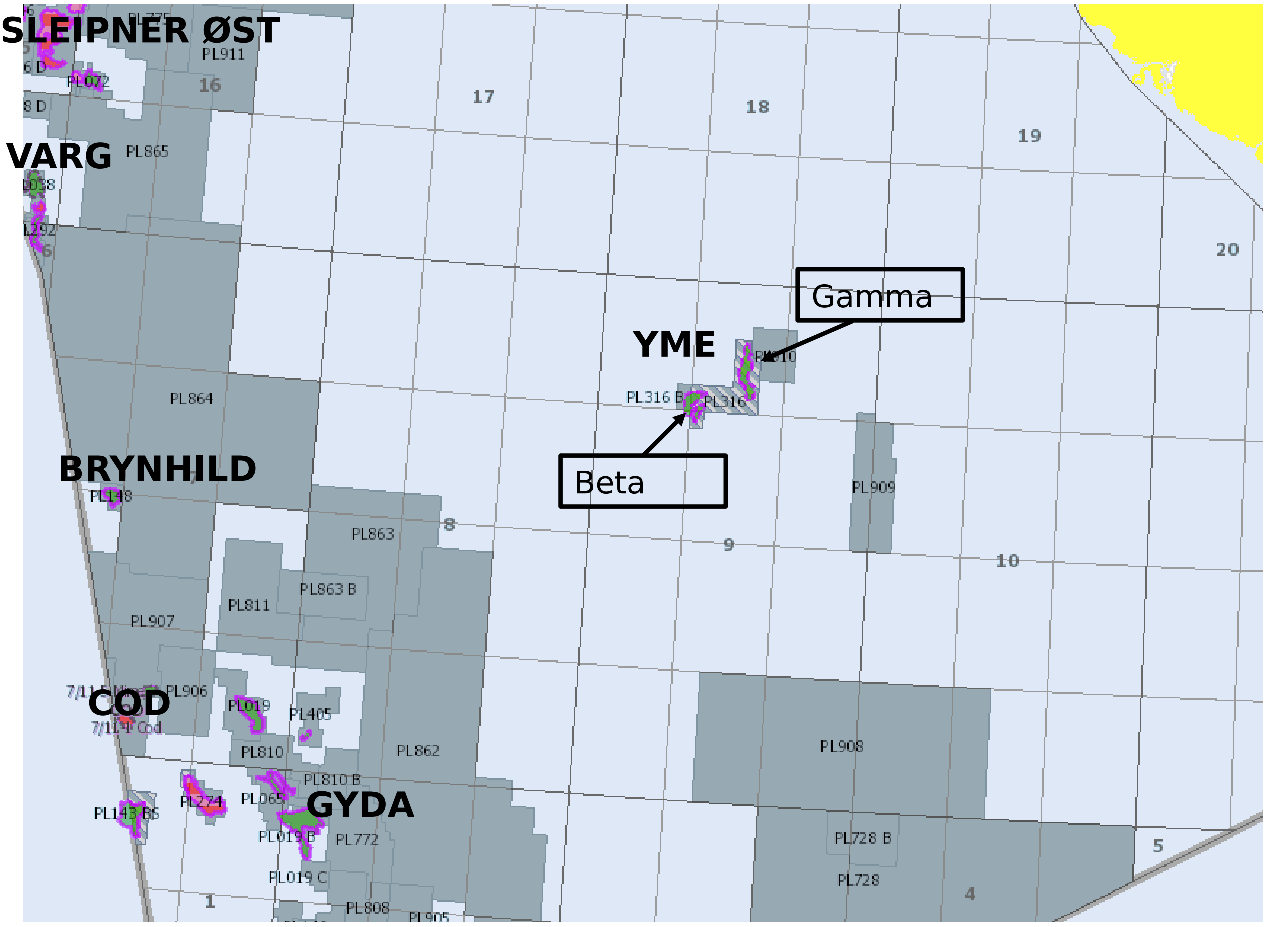


Fig. 4.2 Location of the Yme field in the southern part of the Norwegian North Sea

The licence shares are shown in the table below.

Table 4.6 The licence shares for the Yme field. (%)

Licence	Repsol (Op.)	Lotos	OKEA	Kufpec
PL 316	55	20	15	10

Discovery

The Yme field was discovered in 1987 by the 9/2-1 well in the Gamma structure. In 1990, another oil discovery was made by the 9/2-3 well in the Beta structure, 12 km west of the Gamma structure. The Sandnes formation is the productive reservoir, and is covered by Upper Jurassic shales from the Egersund, Tau and Sauda formations. The primary source rock is the highly organic shale from the Tau Formation and the sealing are provided by the Egersund, Tau and Sauda formations.

Reservoir
The reservoir in Yme is the Middle to Upper Jurassic Sandnes formation at a depth of approximately 3200 meters. The two main structures, Gamma and Beta, are each subdivided into three segments separated by faults. All of these segments, except Beta West, will be redeveloped. The reservoir model have been updated after the last drilling, and the current understanding is that Sandnes formation was deposited in a period of transgression with shoreface sediments in a sandy delta. Channel belt complexes associated with this delta correspond to main feeder channel systems and have the best reservoir properties. The thickness of the Sandnes formation in the area surrounding PL316 is up to 180 metres. The average thickness is 150 m for Gamma and 115 m for Beta. The Sandnes formation is divided into 10 zones, numbered from 1 to 10: YS1 (oldest) to YS10 (youngest).

Development
Yme will be developed with a jack-up MOPU with processing facilities. This will be connected to the existing MOPU storage tank, left by the previous operator Talisman. The oil will be exported by tanker and gas will be used for power generation, gaslift and WAG.
The field will be producing from 12 horizontal production wells supported by 2 WAG injectors on Gamma and 3 water injectors; one on Gamma and two on Beta. Produced water reinjection in combination with a regional aquifer will maintain the reservoir pressure, and provide significant sweep towards the producers. Artificial lift for the production wells will primarily be provided by gas lift, but Gamma East wells will utilise ESP. Yme New Development is based on reuse of existing installations on the Yme field and to the extent possible combine these with repositioned and new installations. Se 4.2.1 Facilities Development for further comments.

Status
DG3 was passed in October 2017, and the PDO was delivered in December the same year. First oil is expected in second quarter 2020.

The recoverable volumes of Yme are classified as "Reserves; Justified for development" (SPE's classification system).

Volumes presented by OKEA
The Initially In-Place Volumes (IIPV) estimates as of 31.12.2017 are given in the RNB2018, and are listed in the table below.

Table 4.7 IIPV for Yme as of 31.12.2017

IIPV, 31.12.2017	P90	P50
Oil/Condensate, MSm3	49.00	54.80
Gas, GSm3	2.90	3.30

AGR comments to IIPV

- General
    - In 2017 two new geological models, one for Beta and one for Gamma, was produced based on new wells in 2009-2010, new 3D interpretation, revised sedimenological model, revised structural understanding and new peterophysical evaluation.
    - The new wells show that there is still considerable uncertainty regarding depth conversion and interpretation of top reservoir. This has been addressed in the Changed plan for development, where variance parameters were used in order to limit the uncertainty range before the STOIIP numbers were compared in the history matching process.
    - Free water levels of the different segments in the two structures is a contributor to the uncertainty in the STOIIP Numbers. Low case, Base case and High case for free water levels have been used separately for each segment in order to take care of the variations.
    - An integrated static uncertainty analysis, described in the Yme New Development "Changed Plan for Development and Operation" gives ranges in STOIIP.
    - The Yme New Development "Changed plan for Development and Operation" have performed several important updates on the modelling. The numbers are slightly down from Yme PDO 2017: Subsurface Support Document , but are still consistent. The P90 value for Yme is assumed to be

equal to the P50 less 10,5%. This is reasonable keeping in mind the long production history on Yme, and a total 37 wells on the field.

- Conclusion
  - In AGR's opinion the IIPV figures are reasonable.

Table 4.8 shows the net reserves for the Yme field, as presented by OKEA.

Table 4.8 Yme net reserves (15 %)
Net reserves 31.12.2017 presented by OKEA

As of 31.12.2017	Interest	1P/P90 (Low estimate)					2P/P50 (Base estimate)				
		Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe	Gross Oil	Gross NGL	Gross Gas	Gross oe	Net oe
	%	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)	(mmboe)
Yme	15%	52.43	0	0	52.43	7.86	64.55	0	0	64.55	9.68
Total Net oe						7.86					9.68
Reserves – TOTAL											
OKEA Net oe						8.51					10.52

AGR comments to reserves

- General
  - The reserves are consistent with the RNB2018 submission.
  - Two independent simulation models (Gamma and Beta) were built directly from the geomodels, with no upscaling. Five rel. perm regions were defined based on permeability classes. The SCAL data are derived from core plugs and PVT is derived from fluid samples. The models were initiated from capillary pressure curves.
  - A lot of emphasis have been made to history matching the models from the five years of production history (1996 - 2001). Static and dynamic model uncertainties were combined to make hundreds of equally probable models. The results were compared to the production history and filtered. The process was repeated in several iterations. A reference model for both Gamma and Beta were then selected. Each well has been history matched on individual level. The history match on well level looks satisfactory.
  - The following most important parameters have been used in the history matching:
    - Aquifer size
    - Pore volume multiplyers
    - Fault communication
    - Critical water saturation
    - Static model (property distribution and channel direction)
  - The models have been adjusted to match the following parameters:
    - Oil and water rate
    - Static and dynamic well pressures
    - Formation pressures obtained by Statoil and Talisman in conjunction with drilling
- The allocated production data is of good quality for most Gamma wells. On Beta there is considerable uncertainty associated with the allocation of production between the Beta wells as they shared the same production line, and the wells were never tested alone.
- Conclusion
  - The production history helps reducing the reserves uncertainty. However, the field is heterogeneous and compartmentalized, and there is still uncertainty about the water cut evolution and drainage of the low permeability zones
  - In AGR's opinion the figures reported by OKEA are reasonable. The reserves uncertainty range of +/- 20 % is acceptable.
  - AGR endorse both the 1P and 2P reserves.

Volumes certified by AGR
Economic evaluations have been carried out for the Yme field based on the costs and production profiles originally supplied by OKEA and reviewed by AGR.

The economic evaluations have confirmed that both the P50 and P90 cases are economically robust under the base oil price. The economic cut-off is reached at the end of technical production profiles for P50 and P90. The key results are summarised below. More details on the estimation of the economic cut-offs together with the production profiles are given in Section A.2 Yme Economic Summary and Production Profiles.

Table 4.9 Net Yme reserves as of 31.12.2017

Reserves, AGR review	1P	2P
Oil, MSm3	1.25	1.54
Gas, GSm^3	0.00	0.00
NGL, GSm^3	0.00	0.00
Total, MSm^{3}o.e.	**1.25**	**1.54**
Total, mmboe	**7.87**	**9.68**

The above reserves are based on sound industry practice and are endorsed.

Table 4.10 Yme Recovery Factors

	Oil RF by end 2017	Oil RF at EUR	Gas RF by end 2017	Gas RF at EUR
Yme	14	33 %	0 %	0 %

References
The main reference provided were:

- Yme New Development Changed Plan for Development and Operation December 2017, Repsol
- Yme PDO 2017: Subsurface Support Document, Revision, Repsol
- OKEA AS, Annual Statement of Reserves 2018

4.2.1 Facilities Development

Project development status
The original PDO for the Yme field submitted on 27 November 2006 and approved in 2007 had to be changed as a consequence of the decision to remove the original production facility on the field. The Changed PDO (by December 2017) assumes that the original production facility will be replaced by a leased jack-up installation with drilling and processing facilities and it also describes the consequences of this change in relation to PDO 2007.

The Yme New Development (YND) is based on reuse of existing installations on the Yme field and to the extent possible, combine these with repositioned and new installations as shown in Fig. 4.3.

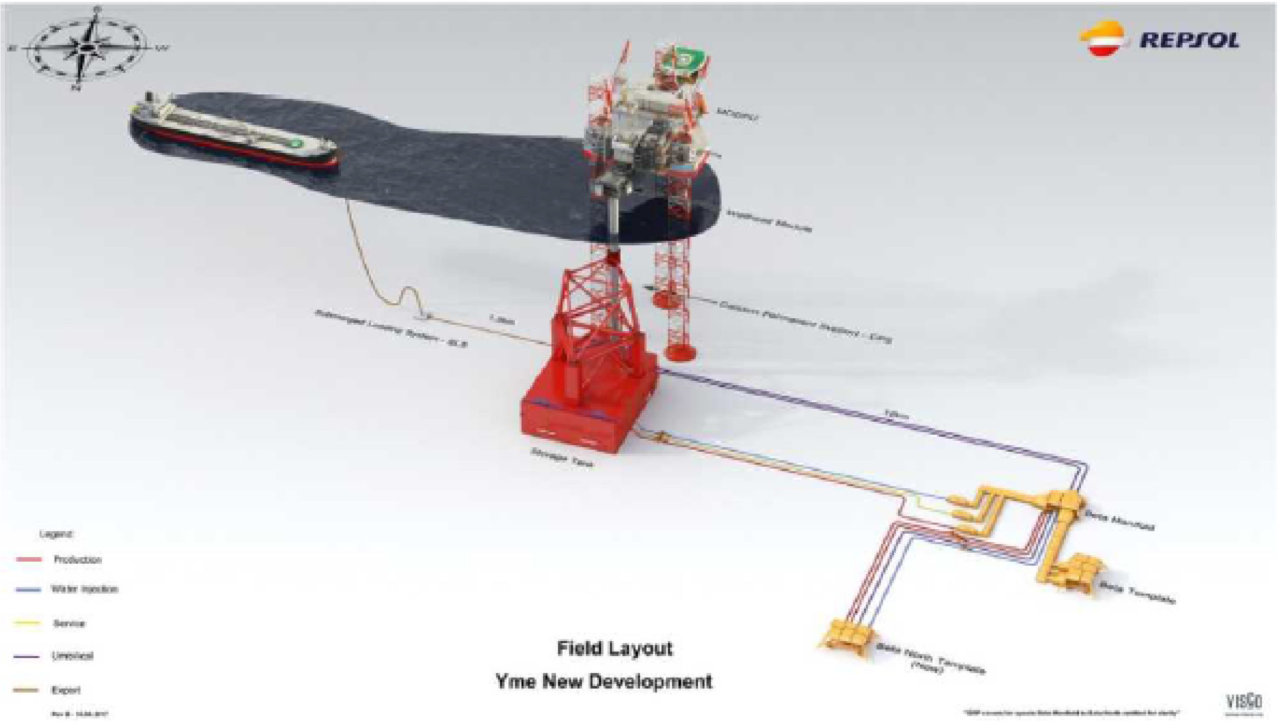


Fig. 4.3 YME field layout

The facilities currently installed on the field (according to PDO 2007) that will be reused, are as follows:

• Storage tank
• Caisson with risers and wells
• Pipelines, umbilicals and subsea facilities at the Beta location
• Submerged Loading System (SLS)

Existing facilities and equipment to be reused have been subjected to a verification program, in addition to the regular maintenance program, in order to ensure safety, functionality, compliance with regulations and integrity are safeguarded for the entire expected lifetime.

Changes and new equipment compared with PDO 2007 are comprised of the following:

• A drilling rig with processing facilities will be installed on the field (Mærsk Inspirer, modified and reassigned from the Volve field)
• A new wellhead module (WHM) will be installed on top of the existing caisson
• A new support structure (CPS) for the caisson
• Beta North: A new subsea template with three wells tied in to the existing Beta manifold (on stream from 2022).

Project plan
The YND project plan has been established to focus on successful delivery of the first oil in the second quarter of 2020, with an internal target of the fourth quarter of 2019. Early identification of obstacles and/or limitations has been determined through development of the project execution plan. The project's main milestones are shown in . Thus, the general goal is to complete the project in 31 months from start of engineering to the first oil.

Table 4.11 YME main milestones

Milestone description	Date
Project approval	October 2017
Caisson Permanent Support (CPS) fabrication complete	June 2018
Caisson Permanent Support (CPS) installation complete	June - August 2018
Existing Subsea Production Control System (SPCS) and Submerged Loading System (SLS) brought up	April - June 2018
Modification campaign Caisson topside	August 2018 - February 2019
Wellhead module (WHM) fabrication complete	March/April 2019
Wellhead module (WHM) installation complete	April-June 2019
SPSC system installation complete	April-June 2019
Submerged loading system installed	April-June 2019
Mærsk Inspirer yard stay	October 2018 - July 2019
Mærsk Inspirer on location on Yme	September 2019
First oil	April 2020
First oil	May 2020
First oil - Beta North	November 2021

The project's critical path is determined by the modification of Mærsk Inspirer. Therefore, the purchase orders' placement of "Long Lead Items" is critical to ensure that the necessary equipment packages are received at the yard in time for installation during the planned yard stay referred to in the main goals. After receipt of "Long Lead Items", the critical path lies within mechanical completion, transport of Mærsk Inspirer, and installation on the Yme field. When Mærsk Inspirer is on site and jacked up, the critical path will follow hook-up to the wellhead.

Project costs (CAPEX, OPEX and ABEX)
The expected investments (capex) for YND are estimated at 8.231 MNOK17. Table 4.12 shows the total expected investments in connection with the development, distributed per year and main activity.

Annual operating costs (opex) are estimated based on actual costs from other projects, expected use from the logistics centre and estimates from contractors. The operating costs are estimated at 980 MNOK17 for a representative average year (2022 selected). Table 4.12 shows the expected total operating costs per year for Yme. Operating costs from Mærsk Drilling reflect the agreed rates that apply for lease and use of Mærsk Inspirer and constitute the main portion of the cost estimate.

The expected removal cost (abex) for YND is shown in Table 4.12 and is estimated at 2.983 MNOK17. The plan calls for removal activities to start in 2028, with completion in 2032.

Table 4.12 Summary of Project Costs

	Annual Investment Costs		Annual Operating Costs		Removal Costs	
Year	**Total MNOK 17**	**Total Nominal**	**Total MNOK 17**	**Total Nominal**	**Total MNOK 17**	**Total Nominal**
2017	791	791	6	6		
2018	3,438	3,507	25	25		
2019	1,533	1,595	17	18		
2020	976	1,035	1,034	1,097		
2021	824	892	1,008	1,091		
2022	499	551	980	1,082		
2023	170	191	1,115	1,256		
2024	-	-	955	1,097		
2025			945	1,107		
2026			1,087	1,299		
2027			932	1,136		
2028			927	1,153		
2029			898	1,138		
2030			207	267		
Total	**8,231**	**8,562**	**10,135**	**11,773**	**2,983**	**3,896**

Project Uncertainties / Risks
YND risk management is focused on identification and mitigation of risks related to HSE, organisation, technical, operational and contract elements with a potential to impact costs, schedules, quality and / or safety.

The most important risks (threats) identified during the project's defining phase are described in Fig. 4.4.

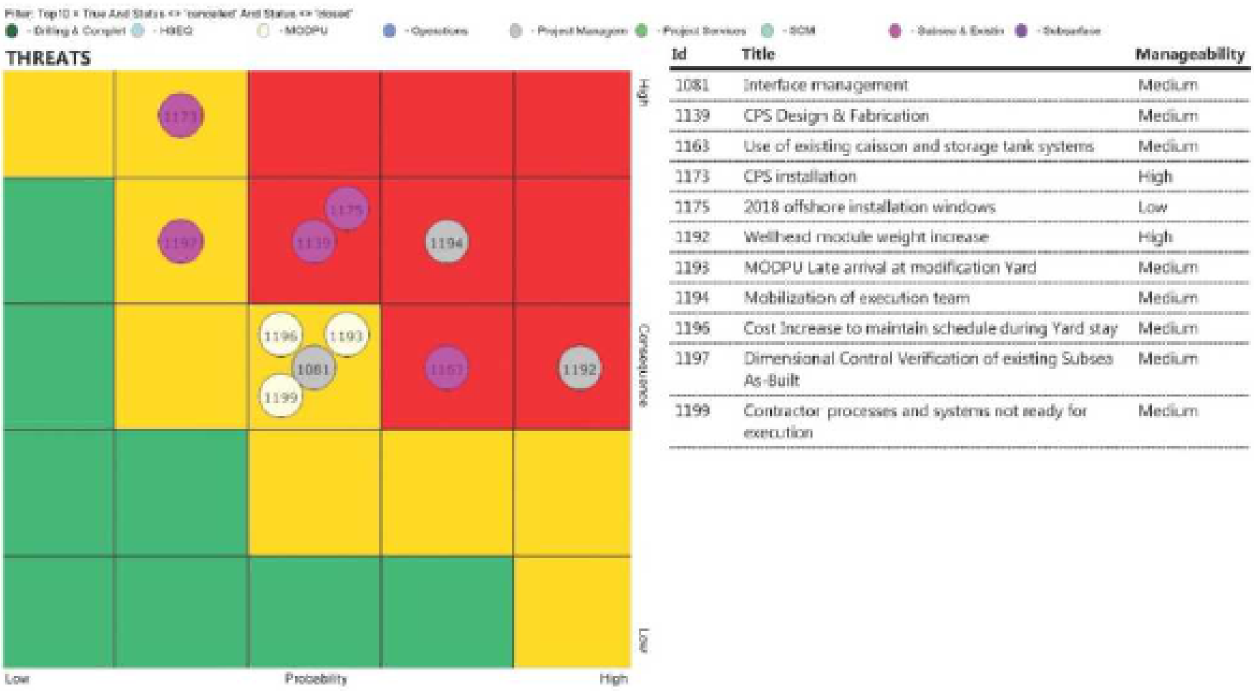


Fig. 4.4 YME main risks (threats)

AGR observations

- AGR's general impression is that the Yme facilities to be re-used have been properly preserved and maintained. This is a result from continuous focus on maintenance and verification programs, to ensure compliance and technical integrity for the expected lifetime. It should be noted that AGR has not seen the detailed tests/inspections/ documentation from the verifications.
- AGR do fully support the new installations solutions and do regard these to be in line with Norwegian

rules and regulations. AGR deem these as technically optimal to make YND fit for the future lifetime.

- AGR has not seen any detailed cost and time estimates given for projects, but in general AGR is much in line with the high level estimates in the new PDO. AGR do, however, have some specific notes;
  - AGR has benchmarked the weights/costs for MI modifications (which are rather comprehensive due to compressor upgrades) and the new Wellhead module with in-house cost data. AGR do find these as highly relevant.
  - General management/Owners Cost seem on the high side when benchmarking on a high level towards similar projects (% comparison).
  - The contingency level (below ~ 4% of CAPEX) seem low even recognizing the use of allowance factors
  - If Beta North subsea costs do include 3 new X-trees , these are deemed to be on the low side
  - AGR do agree in the project execution schedule of 31 months and the defined critical path which has minor float, as AGR see it. Thus MI could be a candidate for some delays.
- AGR consider the facility uncertainties/risks identified as most relevant at the present status of the project. Additionally, AGR would also flag that all flexibles between the new Wellhead module and MI are highly exposed to wind and potentially waves.
- AGR would highlight that the key driver for success seem to be Mærsk Drilling/Mærsk Inspirer (MI) and as such the "lease contract/- handling" is of major importance.

AGR conclusions:

- AGR conclude that the YND facilities (new installations and those to be re-used) don't have any technical "show stoppers" and seem to be an optimal technical solution.
- AGR judge the existing YND field facilities to be in relatively good shape i.e. the installations to be re-used have been properly maintained, having continuous focus on technical - and safety integrity, and together with the new installations do serve the field development design basis and functionality. Further AGR deem YND to potentially serve as a "HUB for the area", having inherent design flexibility for key features such as J-tubes/risers, topside weight and production capacities beyond the indicated ten years lifetime.

References

The main reference provided were:

- Yme New Development, Changed Plan for Development and Operation, December 2017. No supporting documents (as DGSP documents for sanctioning) are reviewed/assessed.

4.2.2 Wells

During the first phase of PDO 2007 a total of 9 wells were drilled on Yme Beta and Gamma for production and injection purposes. These predrilled wells are 4 producers and 2 injectors on Gamma, and 2 producers and 1 injector on Beta. All these wells were completed during the period 2009-2010. The production wells were drilled as horizontal wells and completed with predrilled liners with swell packers in sections with exposed layers of coal in the reservoir and artificial lift in the form of double ESP pumps.

Further plans on Gamma is to drill two producers and one injector from Mærsk Inspirer. On Beta 2 new producers and one injection well are planned from a new subsea template using a leased rig.

AGR observations

- The existing wells have a relatively uncomplicated design, both in wellbore, casing design and completion.
- The uncertainty associated with further use of these wells will be related to the removal of barrier plugs and the initial flow of the wells.

AGR conclusions:

- In the new development plan the old wells will be recompleted using gas lift. The uncertainty related to the ESP's will no longer be relevant.
- The risk related to drilling and completion of further wells is based on previous experience in the field, and should be low.

Appendix A - Economics and production profiles

Economic evaluations have been carried out for the all fields based on the costs and production profiles supplied by OKEA and reviewed by AGR. These evaluations are forward looking from 01.01.2018, thus any historic costs prior to that date have been ignored. All cost profiles have been provided by OKEA and are based on RNB2018. The following general assumptions were made.

- PV Reference date: 01.01.2018

The price assumptions were provided by OKEA. The base oil price profile for certification is listed below, and later referred to as Base.

Table A.1 Price assumptions

Price assumptions	
Oil Price, USD/bbl	60
Gas Price, NOK/Sm3	1.8 (60% of oil price)
NGL Price USD/boe	48 (80% of oil price)
Exchange Rate, NOK/USD	7.75

A.1 Ivar Aasen Economic Summary and Production Profiles

A.1.1 Development and operations assumptions

Ivar Aasen, previously called Draupne Discovery, is located approx 8 km north of Edvard Grieg Field, and covers development of the Ivar Aasen and West Cable structures. The development includes a PDQ, where partly processed oil & gas will be exported to the Edward Grieg platform for further processing and export. Oil export will be to the Grane pipeline and gas export to the SAGE pipeline system.

The platform has a 20 slot drilling template, and the initial development plan included 7 producers and 6 water injectors. Current status; these wells have been drilled according to plan and two more water injectors will be drilled in 2018 to ensure sufficient water injection in the field. The platform receive both electric power and lift gas from Edward Grieg. Ivar Aasen started production on 24th December 2016.

As a Phase 2 of the development, the Hanz discovery will be tied in to Ivar Aasen as a subsea tieback. This is currently scheduled for 2021.

The development costs from the RNB2018 submission were used for the economic evaluation.

A.1.2 Economic results

The key results under the three price scenarios are summarised in the two tables below for P50 and P90 cases. Note that the economic evaluations are forward-looking from 01.01.2018.

Table A.2 Summary of economic results for Ivar Aasen P90 case

OKEA net: 0.554%	**Technical profile Resources net**	**Oil price Base Reserves net**
1st Production	24.12.2016	24.12.2016
Cut-off	31.12.2035	31.12.2030
Oil/condensate, MSm^3	0.08	0.08
Gas, GSm^3	0.02	0.02
NGL, MSm^3 o.e.	0.01	0.01
Total, MSm^3 o.e.	**0.10**	**0.10**
Total, mmboe	**0.64**	**0.62**

Table A.3 Summary of economic results for Ivar Aasen P50 case

OKEA net: 0.554%	**Technical profile Resources net**	**Oil price Base Reserves net**
1st Production	24.12.2016	24.12.2016
Cut-off	31.12.2035	31.12.2035
Oil/condensate, MSm^3	0.11	0.11
Gas, GSm^3	0.02	0.02
NGL, MSm^3 o.e.	0.01	0.01
Total, MSm^3 o.e.	**0.13**	**0.13**
Total, mmboe	**0.84**	**0.84**

A.2 Yme Economic Summary and Production Profiles

A.2.1 Development and operations assumptions

See description in sections 4.2 Yme, 4.2.1 Facilities Development and 4.2.2 Wells for reference.

A.2.2 Economic results

The key results under the three price scenarios are summarised in the two tables below for P50 and P90 cases. Note that the economic evaluations are forward-looking from 01.01.2018.

Table A.4 Summary of economic results for Yme P90 case

OKEA net: 15%	Technical profile Resources net	Oil price Base Reserves net
1st Production	24.12.2016	24.12.2016
Cut-off	31.12.2030	31.12.2030
Oil/condensate, MSm^3	1.25	1.25
Gas, GSm^3	0.00	0.00
NGL, MSm^3o.e.	0.00	0.00
Total, MSm^3o.e.	**1.25**	**1.25**
Total, mmboe	**7.87**	**7.87**

Table A.5 Summary of economic results for Yme P50 case

OKEA net: 15%	Technical profile Resources net	Oil price Base Reserves net
1st Production	24.12.2016	24.12.2016
Cut-off	31.12.2030	31.12.2030
Oil/condensate, MSm^3	1.54	1.54
Gas, GSm^3	0.00	0.00
NGL, MSm^3o.e.	0.00	0.00
Total, MSm^3o.e.	**1.54**	**1.54**
Total, mmboe	**9.68**	**9.68**

Appendix B Abbreviations and definitions

Abbreviation	Definition
1C	Low estimate scenario for Contingent Resources.
1P	Proved Reserves; denotes low estimate scenario for Reserves
2C	Best estimate scenario for Contingent Resources.
2P	Proved plus Probable Reserves; denotes best estimate scenario for Reserves
4D	Four Dimensional (time lapse seismic)
AAPG	American Association of Petroleum Geologists
Aker BP	Aker BP ASA (the name of the client company)
AVO	Amplitude Versus Offsets
bbl	Volume unit, 1 barrel = 42 US gallons ≈ 159 L
BCU	Base Cretaceous Unconformity
Bo	Formation volume factor for oil
BOK	"Beslutning Om Konkretisering". Feasibility decision gate.
BOV	"Beslutning Om Videreføring". Concept selection gate
BRV	Bulk Rock Volume
CAPEX	CAPital EXpenditures
CBM	Controlled Beam Migration
CCA	Conventional Core Analysis, identical to RCA
CGR	Condensate Gas Ratio
CMR	Combinable Magnetic Resonance Tool™ (Schlumberger); nuclear magnetic resonance (NMR) for down-hole fluid measurements
CoS	Chance of success
CPI	Computer Processed Interpretation
D	Darcy
DC	Depth Conversion
DCA	Decline Curve Analysis
DG1	Decision Gate 1; At least one technical concept is demonstrated economical
DG2	Decision Gate 2; Concept selection
DG3	Decision Gate 3; Project sanction; deliver PDO
DST	Drill Stem Test
EC	Engineering Committee
EOS	Equation Of State
EUR	Estimated Ultimate Recovery; identical to resources in this report
Fm	Formation
FMT	Formation Multi-Tester™ (Weatherford); formation pressure data, also MDT, RCI, RFT
FOL	Free Oil Level
FPSO	Floating Production Storage and Offloading vessel
FWL	Free Water Level
GCV	Gross Calorific Value
GDT	Gas Down To
GIIP	Gas Initially In Place
GOC	Gas-Oil Contact
Gp	Group
G	billion (Giga) SI unit multiplier = 10^9
GWC	Gas-Water Contact
HCPV	Hydrocarbon Pore Volume
HM	History Match
IIPV	Initially In-Place Volumes (at the discovery time)
IPV	In-Place Volumes at a specified time after the discovery

Abbreviation	Definition
km	Kilometre
LQ	Living Quarters
LWD	Logging While Drilling
m	meter
mm	million; oilfield unit multiplier
mmbbl	million barrels of stock tank oil
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmrbbl	million reservoir barrels
mD	millidarcy, permeability unit
M	million (Mega) SI unit multiplier = 10^6
MBAL	Material Balance (software)
MC	Management Committee
MD	Measured Depth
MDT	Modular Formation Dynamics Tester™ (Schlumberger); formation pressure data, also FMT, RCI, RFT
MJ	megajoule (million joules)
MNOK	Million NOrwegian Kroner
MOD	Money Of the Day
MOPU	Mobil Offshore Production Unit
MSL	Mean Sea Level
Mt	Million tonnes
MUSD	Million US Dollars
MWD	Measurement While Drilling
NGL	Natural Gas Liquids
NOK	NOrwegian Kroner
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
o.e.	Oil Equivalent. 1 Sm^3 o.e. = 1 Sm^3 oil =1000 Sm^3 gas
ODT	Oil Down To
Op.	Operator
OPEX	OPerating EXpenditures
OWC	Oil-Water Contact, identical to OWC
PDO	Plan for Development and Operations
PDQ	Processing Drilling and Quarter
PRMS	Petroleum Resources Management System
PSDM	Pre-Stack Depth Migration
PVT	Pressure Volume Temperature; fluid properties
PV	Present Value
QC	Quality Control (Quality Check)
rbbl	Reservoir barrel
RCA	Routine Core Analysis, identical to CCA
RCI	Reservoir Characterization Instrument™ (Baker Hughes); formation pressure data, also FMT, MDT, RFT
RF	Recovery Factor
RFT	Repeat Formation Tester™ (Schlumberger); formation pressure data, also FMT, MDT, RCI
RKB	Rotary Kelly Bushing
RMP	Reservoir Managemant Plan
rm^3	Reservoir cubic metre
RNB	Revised National Budget; sheets/forms (NPD)

Abbreviation	Definition
RT	Real Terms
Sm^3	Standard cubic meter
Sw	Water Saturation
SWAG	Simultaneous Water And Gas injection
SCAL	Special Core Analysis
SOF	Structurally Oriented Filter
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SS	Subsea
SSIV	Subsea Isolation Valve
STOIIP	Stock Tank Oil Initially In Place (at the discovery time)
STOIP	Stock Tank Oil In Place at a specified time after the discovery
SWE	Effective Water Saturation
Technical	Used with volumes. Refers to values calculated without economic cut-off
TVD	True Vertical Depth
VSH	Volume of Shale
USD	US Dollar
WCT	Water Cut
OWC	Water-Oil Contact, identical to OWC
WAG	Water Alternating Gas
WPC	World Petroleum Congress
WUT	Water Up To

OKEA AS

Annual financial statements 2017

LETTER FROM THE DIRECTORS 2017

About OKEA AS
OKEA AS ("OKEA" or "the Company") was established in 2015. The Company's aim is to contribute to the value creation on the Norwegian Continental Shelf with cost effective development and operation systems. The Company is located in Trondheim, Norway.

During 2017, the Company completed the following acquisitions of interests in licenses on the Norwegian Continental shelf:

- 5% in the Yme field (PL316/PL316B) from Repsol Norge AS, and
- 40 % in Grevling field (PL038D) from Repsol Norge AS.

A revised Plan for Development and Operation (PDO) for Yme was submitted to the Norwegian authorities in December 2017 and has been approved in 2018.

The Company became the operator for the Grevling field during 2017.

The financial statements
For the financial year 2017; Loss from operating activities was NOK 55,788 thousand. Loss before income tax amounted to NOK 80,494 thousand and Net loss was NOK 11,714 thousand.

At the end of 2017, capitalised deferred tax asset amounted to NOK 85,091 thousand. The amount is mainly related to offshore tax losses.

The operations of the Company are financed through equity and a bond loan. The Company's equity ratio is considered to be at an acceptable level.

Pursuant to § 3-3 of the Norwegian Accounting Act the Board of Directors confirm that the conditions for continued operations as a going concern are present for the Company and that the annual financial statements for 2017 have been prepared under this presumption.

Allocation of loss for the year
In 2017, OKEA posted a net loss of NOK 11,714 thousand. The Board of Directors proposes the following allocation (NOK thousand):

Transferred to accumulated loss: NOK 11,714 thousand

Risk factors
The Company is exposed to risk factors that are common for oil companies in the development and production phase. The Company is also exposed to a variety of financial risks, including credit risk, liquidity risk, interest rate risk, oil price risk and currency risk. It is of the highest priority to the Board of Directors to make sure the company successfully manages these risks by finding and implementing the best risk mitigating actions.

Health, safety and environment/equal opportunities
The Company had 26 employees at year end of which seven are female. At present there are no female members of the Board of Directors. No particular actions have been implemented or are planned to promote gender equality in the Company.

The work environment is considered to be good. Absence from sick leave in 2017 was 0.28% of total working hours. There have been no occurrences or reports of accidents or injuries during the year, and no major or significant material damage.

The operations of the Company could potentially pollute the external environment. The Company together with its joint venture partners work actively on measures that can reduce any negative impact on the environment.

The Company has established and implemented a focused Health, Safety, Environment and Quality strategy and policy, resulting in a proactive stance as well as an ownership culture among employees in all aspects of the business. A primary goal for OKEA is to establish a culture of openness with no barriers related to all aspects of HSEQ both within the Company and when working with stakeholders in order to secure a safe working environment, high level of quality and minimal impact on the environment.

Trondheim, 5th April 2018

Henrik Schröder
Chairman of the Board

Paul Anthony Murray
Board Member

Kaare Gisvold
Board Member

Erik Haugane
CEO

Statement of Comprehensive Income

Amounts in NOK `000	Note	2017	2016 (restated *)
Revenues from crude oil and gas sales	20	38 429	-
Other operating income		5 007	494
Total operating income		**43 435**	**494**
Production expenses		-7 654	-148
Exploration expenses	8	-28 710	-547
Depreciation, depletion and amortization	10	-18 025	-178
Employee benefits expenses	4	-11 707	-13 772
Other operating expenses	5	-33 128	-14 281
Total operating expenses		**-99 223**	**-28 926**
Profit / loss (-) from operating activities		**-55 788**	**-28 432**
Finance income	6	2 392	2 460
Finance costs	6	-27 098	-5 334
Net financial items		**-24 706**	**-2 874**
Profit / loss (-) before income tax		**-80 494**	**-31 307**
Income taxes	7	68 780	25 648
Net profit / loss (-)		**-11 714**	**-5 659**
Other comprehensive income:			
Total other comprehensive income		**-**	**-**
Total comprehensive income / loss (-)		**-11 714**	**-5 659**

* See note 26

Balance Sheet at 31 December

Amounts in NOK `000	Note	31.12.2017	31.12.2016 (restated *)	01.01.2016
ASSETS				
Non-current assets				
Deferred tax assets	7	85 091	37 031	10 616
Goodwill	9	8 057	8 057	-
Exploration and evaluation assets	9	5 752	4 752	-
Oil and gas properties	10	676 378	512 923	-
Furniture, fixtures and office equipment	10	217	224	30
Total non-current assets		**775 495**	**562 987**	**10 646**
Current assets				
Trade and other receivables	11, 22	120 207	105 561	1 995
Restricted cash	12, 22	907 799	-	-
Cash and cash equivalents	12, 22	29 609	37 889	8 744
Total current assets		**1 057 615**	**143 450**	**10 738**
TOTAL ASSETS		**1 833 110**	**706 437**	**21 384**
EQUITY AND LIABILITIES				
Equity				
Share capital	13	24 738	11 337	1 100
Share premium		470 755	216 125	20 900
Unregistered share capital		-	146 968	-
Accumulated loss		-21 667	-9 953	-4 294
Total equity		**473 827**	**364 477**	**17 706**
Non-current liabilities				
Provisions	14	319 668	202 466	-
Interest-bearing loans and borrowings	16, 22	963 312	-	-
Total non-current liabilities		**1 282 979**	**202 466**	**-**
Current liabilities				
Trade and other payables	15, 22	66 013	25 899	2 392
Intercompany loan	17, 22	1 141	20 237	-
Public dues payable		3 596	17 285	1 287
Provisions, current	14	5 554	76 074	-
Total current liabilities		**76 304**	**139 494**	**3 679**
Total liabilities		**1 359 283**	**341 960**	**3 679**
TOTAL EQUITY AND LIABILITIES		**1 833 110**	**706 437**	**21 384**

* See note 26

Trondheim, 5th April 2018

Henrik Schröder
Chairman of the Board

Paul Anthony Murray
Board Member

Kaare Gisvold
Board Member

Erik Haugane
CEO

Statement of Changes in Equity

Amounts in NOK `000	Share capital	Share premium	Unregistered share capital	Accumulated loss	Total equity
Equity at 1 January 2016	1 100	20 900	-	-4 294	17 706
Net profit / loss (-) for the year				-5 659	-5 659
Share issues, cash	5 686	108 043			113 730
Share issues, conversion of debt	4 550	87 182	146 968		238 700
Equity at 31 December 2016	**11 337**	**216 125**	**146 968**	**-9 953**	**364 477**
Equity at 1 January 2017	11 337	216 125	146 968	-9 953	364 477
Net profit / loss (-) for the year				-11 714	-11 714
Registration of share issues in Company Registry	7 348	139 620	-146 968		-
Share issues, cash	3 275	62 225			65 500
Share issues, conversion of debt	2 778	52 786			55 564
Equity at 31 December 2017	**24 738**	**470 755**	**-**	**-21 667**	**473 827**

Statement of Cash Flows

Amounts in NOK `000	Note	2017	2016
Cash flow from operating activities			
Profit / loss (-) before income tax		-80 494	-31 307
Income tax paid/received	7	3 740	-
Depreciation, depletion and amortization	10	18 025	178
Accretion ARO		6 001	-
Change in trade and other receivables		-6 420	-22 491
Change in trade and other payables		17 485	39 505
Change in other non-current items		4 385	-
Net cash flow from / used in (-) operating activities		**-37 278**	**-14 115**
Cash flow from investing activities			
Investement in exploration and evaluation assets	9	-999	-4 752
Investment in oil and gas properties		-123 099	-324 454
Investment in furniture, fixtures and office machines		0	-200
Investment in restricted cash	12	-907 799	-
Net cash flow from / used in (-) investing activities		**-1 031 897**	**-329 406**
Cash flow from financing activities			
Proceeds from intercompany borrowings	17	92 280	258 937
Repayment of intercompany borrowings	17	-58 300	-
Net proceeds from borrowings, bond loan	16	961 415	-
Net proceeds from share issues	13	65 500	113 730
Net cash flow from / used in (-) financing activities		**1 060 895**	**372 666**
Net increase/ decrease (-) in cash and cash equivalents		**-8 280**	**29 145**
Cash and cash equivalents at the beginning of the period		37 889	8 744
Cash and cash equivalents at the end of the period	12	**29 609**	**37 889**
Restricted cash at the end of the period	12	907 799	-
Restricted and unrestricted cash at the end of the period	12	**937 408**	**37 889**

Note 1. Corporate Information

OKEA AS ("OKEA" or "the Company") is a limited liability company incorporated and domiciled in Norway. Its registered office is in Trondheim, Norway.

The Company's aim is to contribute to the value creation on the Norwegian Continental Shelf with cost effective development and operation systems. The Company holds the following interests in licenses:

- 15% interest in the Yme field (PL316/316B)
- 0.554% interest in the Ivar Aasen field (PL338BS)
- 70% interest in the Grevling discovery (PL038D)

The financial statements of OKEA for the year ended 31 December 2017 were authorised for issue in accordance with a resolution of the Board of Directors on 5th April 2018.

Note 2. Accounting Policies

Basis of Preparation

The financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU) and in accordance with the additional requirements following the Norwegian Accounting Act.

These are the first financial statements prepared in accordance with IFRS. The date of transition to these principles is 1 January 2016. The Company's financial statements were previously prepared in accordance with the Norwegian Accounting Act ("NGAAP"). The effects of transition from NGAAP to IFRS are disclosed in note 26.

The financial statements have been prepared under the assumption of going concern and on a historical cost basis, with some exceptions as detailed in the accounting policies set out below.

Balance Sheet Classification

Current assets and current liabilities include items due less than a year from the balance sheet date, and items related to the operating cycle, if longer. Other assets and liabilities are classified as non-current. The current portion of non-current debt is included under current liabilities.

Interest in Oil and Gas Licenses

The Company accounts for its interest in oil and gas licenses based on its ownership interest in the license, i.e. by recording its share of the licenses individual income, expenses, assets, liabilities and cash flows, on a line-by-line basis with similar items in the Company's financial statements.

Acquisitions of Interests in Oil and Gas Licenses

Acquisitions of interests in oil and gas licenses or similar joint operations where the joint operation constitutes a business, are accounted for in accordance with the principles in IFRS 3 Business Combinations. This means that the acquisition method of accounting is used to account for such acquisitions.

Identifiable assets acquired and liabilities and contingent liabilities assumed are measured initially at their fair values at the acquisition date. Acquisition-related costs are expensed as incurred.

The excess of the consideration transferred over the fair value of the net identifiable assets acquired is recorded as goodwill. If, following careful consideration, the consideration transferred is less than the fair value of the net identifiable assets of the joint operation acquired, such difference is recognised directly in profit or loss.

Acquisitions of interests in oil and gas licenses or similar joint operations where the joint operation is not considered to be a business, are accounted for as acquisitions of assets. The consideration for the interest is allocated to individual assets and liabilities acquired.

Foreign Currency Translation and Transactions

The functional currency and the reporting currency of the Company is NOK.

Foreign currency transactions are translated into functional currency using the exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities in foreign currencies are translated into functional currency at the balance sheet date exchange rates. Non-monetary items are translated at the historical exchange rate on the transaction date and non-monetary items that are measured at fair value are translated at the exchange rate on the date when the fair value was determined. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation of monetary assets and liabilities denominated in foreign currencies are recognised in the income statement.

Revenue Recognition

Revenues from the sales of petroleum products are recognised at delivery, and the sales amount of the lifted and delivered volumes are presented as revenues from crude oil and gas sales.

Revenues from sales of services are recorded when the service has been performed.

Underlift and overlift of petroleum products

Underlift and overlift of oil and gas is valued at its net realisable value on the balance sheet date, and the change in under/over lift is presented as other operating income. Underlift and overlift is calculated as the difference between the Company's share of production and its actual sales and are classified as respectively current assets and current liabilities. If accumulated production exceeds accumulated sales there is an underlift (asset) and if accumulated sales exceeds accumulated production there is an overlift (liability).

Property, Plant and Equipment, including Oil and Gas Properties

General

Property, plant and equipment acquired by the Company are stated at historical cost, less accumulated depreciation and any impairment charges. Depreciation of other assets than oil and gas properties are calculated on a straight-line basis and adjusted for residual values and impairment charges, if any.

Ordinary repairs and maintenance costs, defined as day-to-day servicing costs, are charged to the income statement during the financial period in which they are incurred. The cost of major overhauls is included in the asset's carrying amount when it is probable that the Company will derive future economic benefits in excess of the originally assessed standard of performance of the existing asset. Major overhauls are depreciated over the period to the next major overhaul.

Gains and losses on disposals are determined by comparing the disposal proceeds with the carrying amount and are included in operating profit.

Depreciation of Oil and Gas Properties

Capitalised costs for oil & gas fields in production are depreciated individually (on a field level) using the unit-of-production method. The depreciation is calculated based on proved and probable reserves. The rate of depreciation is equal to the ratio of oil and gas production for the period over the estimated remaining proved and probable reserves expected to be recovered at the beginning of the period. The rate of depreciation is multiplied with the carrying value plus estimated future capital expenditure necessary to develop any undeveloped reserves included in the reserve basis. Any changes in the reserves estimate that affect unit-of-production calculations, are accounted for prospectively over the revised remaining reserves.

Development Costs for Oil and Gas Properties

Costs of developing commercial oil and/or gas fields are capitalised. Capitalised development costs and acquisition cost of fields in development are classified as tangible assets (Oil and gas properties).

Intangible Assets

Exploration Costs for Oil and Gas Properties
The Company uses the 'successful efforts' method to account for exploration costs. All exploration costs with the exception of acquisition costs of licenses and drilling costs of exploration wells are charged to expense as incurred.

Drilling costs of exploration wells are temporarily capitalised pending the determination of oil and gas reserves. If reserves are not found, or if discoveries are assessed not to be technically and commercially recoverable, the drilling costs of exploration wells are expensed. Costs of acquiring licenses are capitalised and assessed for impairment at each reporting date.

License acquisition costs and capitalised exploration costs are classified as intangible assets (Exploration and Evaluation Assets) during the exploration phase.

Exploration and Evaluation Assets
Exploration and evaluation assets are assessed for impairment when facts and circumstances suggest that the carrying amount of an exploration and evaluation asset may exceed its recoverable amount, and before reclassification as described below.

Intangible assets relating to expenditure on the exploration for and evaluation of oil and gas resources are reclassified from intangible assets (Exploration and Evaluation Assets) to tangible assets (Oil and gas properties under development) when technical feasibility and commercial viability of the assets are demonstrable, and the decision to develop a particular area is made. The assets are assessed for impairment, and any impairment loss recognised, before such reclassification.

These assets are subject to unit-of-production depreciations if and when production from the field is commenced.

Goodwill
Goodwill arising from acquisitions of interests in oil and gas licenses accounted for in accordance with the principles in IFRS 3 Business Combinations, is classified as intangible assets. Goodwill is not amortised but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate that it might be impaired, and is carried at cost less accumulated impairment losses.

Impairment of Assets

Property, plant and equipment and other non-current assets are subject to impairment testing when there is an indication that the assets may be impaired. At each reporting date the Company assesses whether there is any indication that the assets may be impaired. If any indications exist, an impairment test is performed, i.e. the Company estimates the recoverable amount of the asset.

The recoverable amount is the higher of fair value less expected cost to sell and value in use (present value based on the future use of the asset). If the carrying amount of an asset is higher than the recoverable amount, an impairment loss is recognised in the income statement. The impairment loss is the amount by which the carrying amount of the asset exceeds the recoverable amount.

The value in use is determined by reference to discounted future net cash flows expected to be generated by the asset. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows. An oil and gas field is considered to be one cash generating unit, all other assets are assessed separately.

A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the recoverable amount.

Provisions

General

A provision is recognised when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable (i.e. more likely than not) that an outflow of resources embodying economic benefits will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. Provisions are reviewed at each balance sheet date and adjusted to reflect the current best estimate.

The amount of the provision is the present value of the risk adjusted expenditures expected to be required to settle the obligation, determined using the estimated risk free interest rate adjusted for the Company's own credit risk as discount rate. Where discounting is used, the carrying amount of provision increases in each period to reflect the unwinding of the discount by the passage of time. This increase is recognised as finance cost.

Asset Retirement Obligations

The Company recognises the estimated fair value of asset retirement obligations in the period in which it is incurred. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. This cost includes the cost of dismantlement or removal of oil and gas installations. The present value of the obligations is recognised when the assets are constructed and ready for production, or at the later date when the obligation is incurred.

Related asset retirement costs are capitalised as part of the carrying value of the tangible fixed asset and are depreciated over the useful life of the asset, i.e. unit-of-production method. The liability is accreted for the change in its present value each reporting period. Accretion expense related to the time value of money is classified as part of financial expense.

The provision and the discount rate are reviewed at each balance sheet date.

Contingent Liabilities

Contingent liabilities are not recognised in the financial statements unless probable. Significant contingent liabilities are disclosed, with the exception of contingent liabilities where the probability of the liability occurring is remote.

Interest-bearing loans and borrowings

All loans and borrowings are initially recognised at cost, being the fair value of the consideration received net of issue costs and transaction costs associated with the borrowing.

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest method, with the difference between net proceeds received and the redemption value being recognised in the income statement over the term of the loan. Amortised cost is calculated by taking into account any issue costs and any discount or premium on settlement.

Gains and losses are recognised in net profit or loss when the liabilities are derecognised, as well as through the amortisation process.

Income Taxes

The income tax expense/credit consists of current income tax (taxes payable/receivable) and changes in deferred income taxes.

Current Income Taxes

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the tax authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantially enacted by the balance sheet date.

Oil-exploration companies operating on the Norwegian Continental Shelf under the offshore tax regime can claim a 78% refund of their exploration costs, limited to taxable losses for the year. The refund is paid out in November in the following year. This tax receivable is classified as a current asset.

Current income tax relating to items recognised directly in equity is recognised in equity and not in the income statement.

Deferred Income Taxes

Deferred income tax is provided using the liability method on temporary differences at the balance sheet date between the tax basis of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred income tax assets are recognised for all deductible temporary differences (with the exception of temporary differences on acquisition of licences that is defined as asset purchase), carry forward of unused tax credits and unused tax losses, to the extent that it is probable that the taxable profit will be available against which the deductible temporary differences, and the carry forward of unused tax credits and unused tax losses can be utilised. The carrying amount of deferred income tax assets are reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred income tax asset to be utilised. Unrecognised deferred income tax assets are reassessed at each balance sheet date and are recognised to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

Companies operating on the Norwegian Continental Shelf under the offshore tax regime can claim the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid (including interest) from the tax authorities when operations cease. Deferred tax assets that are based on offshore tax losses carry forward are therefore normally recognised in full.

Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realised or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date.

Deferred income tax assets and deferred income tax liabilities are offset, if a legally enforceable right exists to set off current tax assets against income tax liabilities and the deferred income taxes relate to the same taxable entity and the same taxation authority/tax regime. Timing differences are considered.

Deferred income tax relating to items recognised directly in equity is recognised in equity and not in the income statement.

Uplift

Uplift is a special allowance in the basis for petroleum surtax in Norway. The uplift is computed on the basis of the original capitalised cost of offshore production installations, and amount to 5,3% of the investment per year. The uplift may be deducted from taxable income for a period of four years (i.e. totals 21,2% over four years), starting in the year in which the capital expenditures are incurred. Uplift benefit is recorded when the deduction is included in the current year tax return and impacts taxes payable. Unused uplift may be carried forward indefinitely.

Pensions

According to Norwegian law employees are mandatory members of the Company's Pension Scheme ("obligatorisk tjeneste pensjon"). The scheme is based on a contribution plan. Contributions are paid to pension insurance plans and charged to the income statement in the period to which the contributions relate. Once the contributions have been paid, there are no further payment obligations.

Cash and Cash Equivalents

Cash and cash equivalents comprise of cash on hand, deposits held at call with banks and other short-term highly liquid investments with original maturities of three months or less.

Cash Flow Statement

The cash flow statement is prepared using the indirect method.

Leases (as lessee)
Leases in which most of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases are charged to the income statement on a straight-line basis over the period of the lease.

Cost of Equity Transactions
Transaction costs directly attributable to an equity transaction are recognised directly in equity, net of taxes.

Related Parties
Parties are related if one party has the ability, directly or indirectly, to control the other party or exercise significant influence over the party in making financial or operational decisions. Parties are also related if they are subject to common control.

Transactions between related parties are transfers of resources, services or obligations, regardless of whether a price is charged. All transactions between related parties are made based on the principle of 'arm's length', which is the estimated market price.

Events after the balance sheet date
The financial statements are adjusted to reflect events after the balance sheet date that provide evidence of conditions that existed at the balance sheet date (adjusting events). The financial statements are not adjusted to reflect events after the balance sheet date that are indicative of conditions that arose after the balance sheet date (non-adjusting events). Non-adjusting events are disclosed if significant.

New and amended standards and interpretations issued but not adopted by the Company
A number of new standards and amendments to standards and interpretations are effective for annual periods beginning after 1 January 2017, and have not been applied in preparing these financial statements. The most significant standards are set out below.

IFRS 9 Financial instruments:
IFRS 9 addresses the classification, measurement and derecognition of financial assets and financial liabilities, introduces new rules for hedge accounting and a new impairment model for financial assets. Effective date is 1 January 2018. IFRS 9 did not have any significant effect on the financial statements as of Jan 1, 2018..

IFRS 15 Revenue from contracts with customers:
The IASB has issued a new standard for the recognition of revenue. This will replace IAS 18 which covers contracts for goods and services and IAS 11 which covers construction contracts. The new standard is based on the principle that revenue is recognised when control of a good or service transfers to a customer. The standard permits either a full retrospective or a modified retrospective approach for the adoption. Effective date is 1 January 2018. IFRS 15 did not have any significant effect on the financial statements upon adoption on January 1, 2018.

IFRS 16 Leases:
IFRS 16 was issued in January 2016. It will result in almost all leases being recognised on the balance sheet, as the distinction between operating and finance leases is removed. Under the new standard, an asset (the right to use the leased item) and a financial liability to pay rentals are recognised. The only exceptions are short-term and low-value leases. The accounting for lessors will not significantly change. Effective date is 1 January 2019. At this stage, the Company does not intend to adopt the standard before its effective date, and is assessing the impact of IFRS 16.

Note 3. Critical accounting judgements and estimates

The preparation of financial statements requires management to make judgments, use estimates and assumptions that affect the application of policies and reported amounts of assets, liabilities, revenues and expenses.

Although these estimates are based on management's best knowledge of historical experience and current events, actual results may differ from these estimates. The estimates and the underlying assumptions are reviewed on an ongoing basis.

Currently, the Company's most important accounting estimates are related to the following items:

Impairment

The Company reviews whether its non-financial assets have suffered any impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An asset is written down to its recoverable amount when the recoverable amount is lower than the carrying value of the asset. The recoverable amount is the higher of fair value less expected cost to sell and value in use (present value based on the future use of the asset).

All impairment assessment calculations require a high degree of estimation, including assessments of the expected cash flows from the cash generating unit and the estimation of applicable discount rates. Impairment testing requires long-term assumptions to be made concerning a number of economic factors such as future production levels, market conditions, production expense, discount rates and political risk among others, in order to establish relevant future cash flows. There is a high degree of reasoned judgement involved in establishing these assumptions, and in determining other relevant factors.

Asset Retirement Obligations

Production of oil and gas is subject to statutory requirements relating to decommissioning and removal once Production has ceased. Provisions to cover these future asset retirement obligations must be accrued for at the time the statutory requirement arises. The ultimate asset retirement obligations are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change, for example, in response the changes in reserves or changes in laws and regulations or their interpretation.

Depreciation of Oil and Gas Properties

Oil and gas properties in production are depreciated using the unit-of-production method. The depreciation is calculated based on proved and probable reserves. The rate of depreciation is equal to the ratio of oil and gas production for the period over the estimated remaining proved and probable reserves expected to be recovered at the beginning of the period. The rate of depreciation is multiplied with the carrying value plus estimated future capital expenditure necessary to develop any undeveloped reserves included in the reserve basis. The reserves estimates and the estimates of future capital expenditure is associated with uncertainty.

Note 4. Employee benefits expenses

Specification of employee benefits expenses

Amounts in NOK `000	2017	2016
Salary expenses	33 789	24 530
Employer's payroll tax expenses	5 319	3 859
Pensions	3 651	2 312
Other personnel expenses	942	310
Charged to operated licences	-14 876	-
Reclassified to oil and gas properties under development	-17 117	-17 238
Total employee benefits expense	**11 707**	**13 772**
Number of man-years during the year	26	17

Pensions

The Company has a defined contribution pension plan for its employees which satisfies the statutory requirements in the Norwegian law on required occupational pension ("lov om obligatorisk tjenestepensjon").

Compensation to Chief Excecutive Officer (CEO):

Amounts in NOK `000	2017	2016
Salary	2 368	2 199
Pension	155	157
Other benefits	11	12
Total compensation to CEO	**2 535**	**2 368**

Compensation to Board of Directors:

Amounts in NOK `000	2017	2016
Director's fees	-	-
Total compensation to Board of Directors	**-**	**-**

There is no agreement regarding severance pay on termination of employment or agreement regarding bonus to the CEO or to members of the Board of Directors. No loans have been granted and no guarantees have been issued to the CEO or any member of the Board of Directors.

Note 5. Other operating expenses

Specification of other operating expenses

Amounts in NOK `000	2017	2016
Lease expenses	3 081	2 643
Technical consultants	12 155	51 429
Business consultants	12 795	6 656
Travel expenses	3 721	2 445
Insurance	2 695	-
Other operating expenses	3 813	5 449
Charged to operated licences	-2 960	-
Reclassified to oil and gas properties under development	-2 171	-54 341
Total other operating expenses	**33 128**	**14 281**

Auditor's fees (ex. VAT)

Amounts in NOK `000	2017	2016
Auditor's fee	855	150
Other attestation services	118	92
Tax advisory	-	188
Other services	223	25
Total auditor's fees	**1 196**	**455**

Note 6. Financial items

Amounts in NOK `000	2017	2016
Interest income	500	110
Exchange rate gain	1 892	2 350
Total finance income	**2 392**	**2 460**
Interest expense intercompany	-2 491	-2 057
Interest expense bond loan	-10 096	-
Other interest expense	-133	-591
Exchange rate loss	-8 236	-2 175
Unwinding of discount asset retirement obligations	-6 001	-593
Other financial expense	-141	82
Total finance costs	**-27 098**	**-5 334**

Note 7. Taxes

Income taxes recognised in the income statement

Amounts in NOK `000	2017	2016
Change deferred tax in balance	48 061	21 908
Tax refund current year	20 719	3 740
Total income taxes recognised in the income statement	**68 780**	**25 648**

Reconciliation of income taxes

Amounts in NOK `000	2017	2016
Profit / loss (-) before income taxes	**-80 494**	**-31 307**
Expected income tax at nominal tax rate, 24% (2016: 25%)	19 319	7 827
Expected petroleum tax, 54% (2016: 53%)	43 467	16 592
Permanent differences	-208	-59
Effect of uplift	10 181	2 218
Financial items	-8 766	-1 262
Effect of new tax rates	337	236
Adjustments previous year and other	4 450	96
Total income taxes recognised in the income statement	**68 780**	**25 648**
Effective income tax rate	**85 %**	**82 %**

Specification of tax effects on temporary differences, tax losses and uplift carried forward

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Tangible and intangible non-current assets	-335 377	-233 005	-6
Provisions	245 873	217 261	-
Interest-bearing loans and borrowings	-5 069	-	-
Current items	-2 526	-136	-
Tax losses carried forward, offshore, 23%	51 824	12 352	3 719
Tax losses carried forward, offshore, 55%	100 520	25 497	6 903
Uplift carried forward, offshore 55%	29 847	15 061	-
Total deferred tax assets / liabilities (-)	85 091	37 031	10 616
Valuation allowance for deferred tax assets	-	-	-
Total deferred tax assets / liabilities (-) recognised	**85 091**	**37 031**	**10 616**

Change in deferred taxes

Amounts in NOK `000	2017	2016
Deferred tax income / expense (-)	48 061	21 908
Deferred tax recognized on acquisitions		4 507
Taxes charged to equity	-	-
Total change in deferred tax assets	**48 061**	**26 415**

Deferred tax is calculated based on tax rates applicable on the balance sheet date. Ordinary income tax is 24% (from 2018: 23%) , to which is added a special tax for oil and gas companies at the rate of 54% (from 2018: 55%), giving a total tax rate of 78%.

Companies operating on the Norwegian Continental Shelf under the offshore tax regime can claim the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid in cash (including interest) from the tax authorities when operations cease. Deferred tax assets that are based on offshore tax losses carried forward are therefore normally recognised in full.

There is no time limit on the right to carry tax losses forward in Norway.

Note 8. Exploration expenses

Specification of exploration expense

Amounts in NOK `000	2017	2016
Share of exploration expenses from participation in licences (from billing)	23 752	547
Seismic and other exploration expenses, outside billing	4 958	-
Total exploration expense	**28 710**	**547**

Note 9. Intangible assets

Amounts in NOK `000	Goodwill	Exploration and evaluation assets	Total
2017			
Cost at 1 January 2017	8 057	4 752	12 809
Additions	-	999	999
Disposals	-	-	-
Expensed exploration expenditures previously capitalised	-	-	-
Cost at 31 December 2017	**8 057**	**5 752**	**13 809**
Accumulated amortisation and impairment at 1 January 2017	-	-	-
Amortisation for the year	-	-	-
Impairment	-	-	-
Disposals	-	-	-
Accumulated amortisation and impairment at 31 December 2017	**-**	**-**	**-**
Carrying amount at 31 December 2017	**8 057**	**5 752**	**13 809**
2016			
Cost at 1 January 2016	-	-	-
Additions	8 057	4 752	12 809
Disposals	-	-	-
Expensed exploration expenditures previously capitalised	-	-	-
Cost at 31 December 2016	**8 057**	**4 752**	**12 809**
Accumulated amortisation and impairment at 1 January 2016	-	-	-
Amortisation for the year	-	-	-
Impairment	-	-	-
Disposals	-	-	-
Accumulated amortisation and impairment at 31 December 2016	**-**	**-**	**-**
Carrying amount at 31 December 2016	**8 057**	**4 752**	**12 809**

Note 10. Tangible fixed assets

Amounts in NOK `000	Oil and gas properties in production	Oil and gas properties under development	Furniture, fixtures and office machines	Total
2017				
Cost at 1 January 2017	123 039	390 056	233	513 327
Additions	18 956	123 083	-	142 038
Removal and decommissioning asset	-471	39 905		39 434
Disposals				-
Transfer of assets				-
Cost at 31 December 2017	**141 524**	**553 044**	**233**	**694 800**
Accumulated depreciation and impairment at 1 January 2017	-171	-	-9	-180
Depreciation for the year	-18 018	-	-7	-18 025
Impairment	-	-	-	-
Disposals	-	-	-	-
Accumulated depreciation and impairment at 31 December 2017	**-18 189**	**-**	**-15**	**-18 205**
Carrying amount at 31 December 2017	**123 334**	**553 044**	**217**	**676 595**
2016				
Cost at 1 January 2016	-	-	33	33
Additions	-	237 589	200	237 789
Removal and decommissioning asset	-	275 505	-	275 505
Disposals	-	-	-	-
Transfer of assets	123 039	-123 039	-	-
Cost at 31 December 2016	**123 039**	**390 056**	**233**	**513 327**
Accumulated depreciation and impairment at 1 January 2016	-	-	-2	-2
Depreciation for the year	-171	-	-7	-178
Impairment	-	-	-	-
Disposals	-	-	-	-
Accumulated depreciation and impairment at 31 December 2016	**-171**	**-**	**-9**	**-180**
Carrying amount at 31 December 2016	**122 867**	**390 056**	**224**	**513 147**
Depreciation plan	Unit of Production	1)	Linear	
Estimated useful life (years)	N/A		3 - 5	

1) Depreciation starts when the asset is in production.

Amounts in NOK `000	2018	2019	2020	2021
Committed capital expenditure for existing licenses *)	489 000	406 000	291 000	325 000

*) Commited capital expenditure related to Yme New Development will be paid from escrow account established in connection with the bond loan. See notes 12 and 16 for further information.

Note 11. Trade and other receivables

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Accounts receivable	1 875	6 583	-
Accrued revenue	2 227	-	-
Prepayments	2 892	1 109	951
Working capital, joint operations	21 255	16 014	-
Escrow receivable, Yme removal	64 681	77 335	-
Underlift	5 501	494	-
VAT receivable	557	-	1 043
Tax refund	20 719	3 740	-
Other receivables	500	284	-
Total trade and other receivables	**120 207**	**105 561**	**1 995**

The receivables all mature within one year.

Note 12. Restricted cash, Cash and cash equivalents

Restricted cash:

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Bank deposit, restricted, escrow accounts *	907 799	-	-
Total restricted cash	**907 799**	**-**	**-**

* See information about the escrow accounts established in connection with the bond loan in note 16.

Cash and cash equivalents:

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Bank deposits, unrestricted	27 487	36 283	7 906
Bank deposit, employee taxes	2 122	1 606	838
Total cash and cash equivalents	**29 609**	**37 889**	**8 744**

Note 13. Share capital and shareholder information

Number of shares	Ordinary shares	Preference shares	Total shares
Outstanding shares at 1.1.2016	10 000	1 000	11 000
New shares issued during 2016:			
Issued in connection with debt conversion	460	45 566	46 026
Issued in exchange for cash	3 690	52 649	56 339
Number of outstanding shares at 31 December 2016	**14 150**	**99 215**	**113 365**
New shares issued during 2017:			
Issued in connection with debt conversion	74	101 032	101 106
Issued in exchange for cash	160	32 750	32 910
Number of outstanding shares, before share split 1:100 on 12 December 2017	**14 384**	**232 997**	**247 381**
Number of outstanding shares at 31 December 2017, after share split 1:100	**1 438 400**	**23 299 700**	**24 738 100**

Nominal value NOK per share at 31 December 2017, after share split 1:100	1
Share capital NOK at 31 December 2017	24 738 100

At 31 December 2017 the Company had two classes of shares. The holders of the preference shares had a preferred right to a cumulative 8% dividend on invested preference capital as well as return of capital from the Company before the holders of ordinary shares would receive any return of capital or dividend.

In 2018 OKEA has restructured the Company's equity, by way of transforming the preference shares into ordinary shares. The restructuring included a reduction of the Company's share capital, by repayment of the par value of the preference shares with NOK 23 299 700, from NOK 24 738 100 to NOK 1 438 400. Subsequent to the share capital reduction, a related increase of the Company's share capital with NOK 1 686 600, from NOK 1 438 400 to NOK 3 125 000, where the amount paid out of the Company in the share capital reduction (by way of establishing a receivable on the Company) was used as contribution on the new shares that were issued. The net effect of this restructuring of the Company's equity was a transforming of the preference shares into ordinary shares.

OKEA has in 2018 issued 590 144 new shares at a price of NOK 179 paid in cash, adding MNOK 105.6 in total new equity.

Shareholders, number of shares	Ordinary shares	Preference shares	% Share
OKEA Holdings Ltd	1 188 400	23 299 700	99,0 %
Other shareholders (*)	250 000	-	1,0 %
Total	**1 438 400**	**23 299 700**	**100,0 %**

(*) Erik Haugane (CEO) indirectly controls 0.2 % of the shares through Kørven AS. Ola Borten Moe (Board Member in 2017) also indirectly controls 0.2% of the shares through Skjefstad Vestre AS.

Note 14. Provisions

Non-current provisions:

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Provision at 1 January	202 466	-	-
Additions	107 507	201 873	-
Changes in Operator's estimate	3 694	-	-
Unwinding of discount	6 001	593	-
Total non-current provisions at 31 December	**319 668**	**202 466**	**-**
Of this:			
Asset retirement obligations	309 668	202 466	-
Accrued consideration from acquisitions of interests in licenses	10 000	-	-

Asset retirement obligations
Provisions for asset retirement obligations represent the future expected costs for close-down and removal of oil equipment and production facilities. The provision is based on the Operator's best estimate. The net present value of the estimated obligation is calculated using a discount rate of 3%. The assumptions are based on the economic environment around the balance sheet date. Actual asset retirement costs will ultimately depend upon future market prices for the necessary works which will reflect market conditions at the relevant time. Furthermore, the timing of the close-down is likely to depend on when the field ceases to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

Current provisions:

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Asset retirement obligation related to the ongoing removal of installations on the Yme field	5 554	76 074	-
Total current provisions at 31 December	**5 554**	**76 074**	**-**

Note 15. Trade and other payables

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Trade creditors	7 765	2 972	1 701
Holiday pay	3 743	2 698	691
Working capital, joint operations	34 837	18 064	-
Accrued interest bond loan	9 238	-	-
Accrued consideration from acquisitions of interests in licenses	8 940	-	-
Other accrued expenses	1 490	2 164	-
Total trade and other payables	**66 013**	**25 899**	**2 392**

The payables all mature within 6 months.

Note 16. Interest-bearing loans and borrowings

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Bond loan	985 350	-	-
Capitalized fees bond loan	-22 038	-	-
Total Interest-bearing loans and borrowings	**963 312**	**-**	**-**

In November 2017 the Company entered into a secured bond loan of USD 120 million. Maturity date for the entire loan is in November 2020. Interest rate is fixed at 7,5% with half-yearly interest payments.

The bond loan has security in all major assets of the Company and will be used to fund the Yme development as required by the loan agreement. When Yme is in production any unused loan amount may be used to fund other field developments. The net proceeds have been placed on an escrow account until released for Yme development purposes. USD 70 million of the proceeds have been converted into NOK to reflect the expected NOK denominated investments.

The bond agreement puts certain restrictions on dividend payments and capital reductions. The bond loan has financial covenants in addition to requirements with respect to equity increases. In order to fully utilize the proceeds from the bond loan, the loan agreement stipulates that new equity of in total USD 18 million is to be paid in and registered. The equity increases are to be made in tranches in advance of the utilization of the proceeds from the bond loan. Approximately USD 14 million of new equity has been paid in and registered in 2018.

Changes in Intererest-bearing loans and borrowings:

Amounts in NOK `000	31.12.2017	31.12.2016
Interest bearing loans and borrowings 1 January	-	-
Cash flows:		
Gross proceeds from borrowings, bond loan	984 312	-
Transaction costs, bond loan	-22 897	-
Total cash flows:	**961 415**	
Non-cash changes:		
Amortization of transaction costs, bond loan	859	-
Foreign exchange movement, bond loan	1 038	-
Interest bearing loans and borrowings 31 December	**963 312**	**-**

Note 17. Intercompany loan

Amounts in NOK `000	31.12.2017	31.12.2016	01.01.2016
Loan from majority shareholder OKEA Holdings Ltd	1 141	20 237	-
Total intercompany loan	**1 141**	**20 237**	**-**

Interest rate is 5%.

Changes in Intercompany loan:

Amounts in NOK `000	31.12.2017	31.12.2016
Intercompany loan 1 January	20 237	-
Cash flows:		
Proceeds from intercompany borrowings	92 280	258 937
Repayment of intercompany borrowings	-58 300	-
Total cash flows:	**54 217**	**258 937**
Non-cash changes:		
Conversion of debt to equity	-55 564	-238 700
Accrued interest	2 488	-
Interest bearing loans and borrowings 31 December	**1 141**	**20 237**

Note 18. Commitments and Contingencies

The Company has not been involved in any legal or financial disputes in 2017 or 2016.

Minimum work programmes
The Company is required to participate in the approved work programmes for the licenses. See note 10 for a specification of future committed capital expenditure.

Liability for damages/insurance
The Company's operations involves risk for damages, including pollution. Installations and operations are covered by an operations insurance policy.

Note 19. Related party transactions

Purchases of services from related parties:

Amounts in NOK `000	2017	2016
Seacrest Capital Group Ltd *	3 534	-
Kyllingstad, Kleveland Advokatfirma DA **	173	3 843

* Seacrest Capital Group Ltd is the controlling party of OKEA's majority shareholder OKEA Holdings Ltd.

** The Managing Partner of Kyllingstad, Kleveland Advokatfirma DA was a Board Member of OKEA through 2016.

Accounts payable, related parties:

Amounts in NOK `000	2017	2016
Seacrest Capital Group Ltd	3 534	-

See note 4 for information about compensation to CEO and Board of Directors.

See note 17 for information about loan from majority shareholder OKEA Holdings Ltd.

Note 20. Segment reporting

The Company has identified its reportable segments based on the nature of the risk and return within its business. The Company's only business segment is development and production of oil and gas on the Norwegian Continental Shelf.

All of the Company's sales revenue recognised in 2017 is from sale to one oil company which is a subsidiary of an international oil company with S&P long-term credit rating A+.

Note 21. Operating Leases

The Company has entered into an operating lease for office facilities. The lease has no arrangements regarding contingent payments and does not contain any restrictions on the company's dividend policy or financing.

Operating expenses related to lease agreements accounted for as operating leases

Amounts in NOK `000	2017	2016
Office, parking and equipment	3 081	2 643
Total	**3 081**	**2 643**

Future minimum lease payments under non-cancellable lease agreements

Amounts in NOK `000	2017	2016
Within 1 year	1 852	1 852
1 to 5 years	3 105	4 957
After 5 years		
Total	**4 957**	**6 808**

Note 22. Financial instruments

Financial instruments by category
Amounts in NOK '000

Year ended 31 December 2017

Financial assets

Amounts in NOK '000	Loans and receivables	Fair value through profit or loss	Total carrying amount
Trade and other receivables *	83 021		83 021
Restricted cash	907 799		907 799
Cash and cash equivalents	29 609		29 609
Total	**1 020 428**	**-**	**1 020 428**

Financial liabilities

Amounts in NOK '000	Amortized cost	Fair value through profit or loss	Total carrying amount
Trade and other payables *	31 773		31 773
Intercompany loan	1 141		1 141
Interest-bearing loans and borrowings	963 312		963 312
Total	**996 225**	**-**	**996 225**

* Prepaid expenses, accrued receivables and accrued expenses are not included.

Year ended 31 December 2016

Financial assets

Amounts in NOK '000	Loans and receivables	Fair value through profit or loss	Total carrying amount
Trade and other receivables *	99 933		99 933
Restricted cash	-		-
Cash and cash equivalents	37 889		37 889
Total	**137 822**	**-**	**137 822**

Financial liabilities

Amounts in NOK '000	Amortized cost	Fair value through profit or loss	Total carrying amount
Trade and other payables *	23 735		23 735
Intercompany loan	20 237		20 237
Interest-bearing loans and borrowings	-		-
Total	**43 971**	**-**	**43 971**

* Prepaid expenses, accrued receivables and accrued expenses are not included.

Year ended 31 December 2015 (01.01.2016)

Financial assets

Amounts in NOK '000	Loans and receivables	Fair value through profit or loss	Total carrying amount
Trade and other receivables *	-		-
Restricted cash	-		-
Cash and cash equivalents	8 744		8 744
Total	**8 744**	**-**	**8 744**

Financial liabilities

Amounts in NOK '000	Amortized cost	Fair value through profit or loss	Total carrying amount
Trade and other payables *	2 392		2 392
Intercompany loan	-		-
Interest-bearing loans and borrowings	-		-
Total	**2 392**	**-**	**2 392**

* Prepaid expenses, accrued receivables and accrued expenses are not included.

Fair value of financial instruments
It is assessed that the carrying amounts of financial assets and liabilities, except for interest-bearing loans and borrowings, is approximately equal to its fair values. For interest-bearing loans and borrowings, the fair value is estimated to be NOK 985 350 thousand at year end 2017. This estimation is based on no material change in market interest rate and credit risk since the borrowing.

Note 23. Financial Risk Management

Overview
The Company is exposed to a variety of risks, including credit risk, liquidity risk, interest rate risk, oil price risk and currency risk. This note presents information about the Company's exposure to each of the above mentioned risks, and the Company's objectives, policies and processes for managing such risks. The note also presents the Company's objectives, policies and processes for managing capital.

Credit risk
The Company has no significant credit risk. The Company is exposed to credit risk related to trade receivables and cash and cash equivalents. Sales are only made to customers that have not experienced any significant payment problems. Cash and cash equivalents are receivables from banks.

Liquidity risk
Liquidity risk is the risk of being unable to pay financial liabilities as they fall due. The Company's approach to managing liquidity risk is to ensure that it will always have sufficient liquidity to meet its financial liabilities as they fall due, under normal as well as extraordinary circumstances, without incurring unacceptable losses or risking damage to the Company's reputation.

The table below shows a maturity analysis for financial liabilities:
The cash flows below assumes repayment on the latest date available, even if expected repayment may be earlier.

31.12.2017

Amounts in NOK `000	Carrying amount	Cash Flow	< 1 year	1-5 Year
Trade and other payables	31 773	31 773	31 773	
Intercompany loan	1 141	1 141	1 141	
Interest-bearing loans and borrowings	963 312	985 350		985 350
Total financial liabilities	**996 225**	**1 018 264**	**32 914**	**985 350**

31.12.2016

Amounts in NOK `000	Carrying amount	Cash Flow	< 1 year	1-5 Year
Trade and other payables	23 735	23 735	23 735	
Intercompany loan	20 237	20 237	20 237	
Interest-bearing loans and borrowings	-	-		
Total financial liabilities	**43 971**	**43 971**	**43 971**	**-**

01.01.2016

Amounts in NOK `000	Carrying amount	Cash Flow	< 1 year	1-5 Year
Trade and other payables	2 392	2 392	2 392	
Intercompany loan	-	-	-	
Interest-bearing loans and borrowings	-	-		
Total financial liabilities	**2 392**	**2 392**	**2 392**	**-**

The table below shows a maturity analysis for financial assets:

31.12.2017

Amounts in NOK `000	Carrying amount	Cash Flow	< 1 year	1-5 Year
Trade and other receivables	83 021	83 021	83 021	
Restricted cash	907 799	907 799	907 799	
Cash and cash equivalents	29 609	29 609	29 609	
Total financial assets	**1 020 428**	**1 020 428**	**1 020 428**	**-**

Note 23. Financial Risk Management (continued)

31.12.2016

Amounts in NOK `000	Carrying amount	Cash Flow	< 1 year	1-5 Year
Trade and other receivables	99 933	99 933	99 933	
Restricted cash	-	-	-	
Cash and cash equivalents	37 889	37 889	37 889	
Total financial assets	**137 822**	**137 822**	**137 822**	**-**

01.01.2016

Amounts in NOK `000	Carrying amount	Cash Flow	< 1 year	1-5 Year
Trade and other receivables	-	-	-	
Restricted cash	-	-	-	
Cash and cash equivalents	8 744	8 744	8 744	
Total financial assets	**8 744**	**8 744**	**8 744**	**-**

Interest rate risk

The Company has no borrowings with floating interest rate conditions and is consequently not exposed to interest rate risk related to borrowings. The bond loan has fixed interest rate at 7,5%.

Currency risk

The Company is exposed to foreign exchange rate risk related to the value of NOK relative to other currencies, mainly due to oil sales i USD, operational costs in USD and development costs in USD.

At 31 December 2017 the Company is exposed to exchange rate risk mainly due to bank deposits, escrow receivable related to Yme removal and bond loan in USD.

Sensitivity analysis at 31 December 2017:

If the NOK had gained 10% against the USD at 31 december 2017, the Company's net profit would have been NOK 40.1 million higher.

If the NOK had weakened 10% against the USD at 31 december 2017, the Company's net profit would have been NOK 40.1 million lower.

Sensitivity analysis at 31 December 2016:

If the NOK had gained 10% against the USD at 31 december 2016, the Company's net profit would have been NOK 5.9 million lower.

If the NOK had weakened 10% against the USD at 31 december 2016, the Company's net profit would have been NOK 5.9 million higher.

Oil price risk

The Company's revenue is from oil sales which is exposed to fluctuations in the oil price level.

Capital management

The overall objective of the Company is to ensure that it maintains a strong financial position and healthy capital ratios in order to support its business and maximise shareholder value.

The Company manages its capital structure, and makes adjustments to it, in light of changes in economic conditions.

Note 24. Asset acquisitions

During 2017 and 2016 the Company completed the following acquisitions in interests in licenses on the Norwegian Continental shelf, accounted for as acquisitions of assets:

Year	License	Name	Interest	Seller	Effective date	Completion
2017	PL316/316B	Yme	5 %	Repsol Norge AS	01.01.2017	30.11.2017
2016	PL316/316B	Yme	10 %	Wintershall Norge AS	01.01.2016	30.11.2016
2016	PL038D	Grevling	30 %	Aker BP ASA	01.01.2016	31.10.2016

In addition, OKEA has increased its interest in PL038D Grevling with 40% from 30% to 70% during 2017. Subsequent to this increase in interest, the Company became the operator for this field.

Note 25. Business combinations

Acquisition of 0,554% interest in Ivar Aasen Unit in 2016

In July 2016 the Company completed the acquisition of a 0,554% interest in Ivar Aasen Unit (PL338BS) from OMV (Norge) AS. Effective date for the transaction was 1 January 2016. It is assessed that this transaction represent a business combination.

The excess of the consideration inclusive pro&contra settlement over the fair value of the net identifiable assets acquired is recorded as goodwill, and amounts to NOK 8 057 thousand.

The acquired business contributed net profit after tax of NOK 51 thousand to the Company for the period from acquisition to 31 December 2016. If the acquisition had occurred on 1 January 2016, pro-forma net loss for the twelve months ending 31 December 2016 would have been unchanged at NOK 5 659 thousand, since Ivar Aasen was under development until end of 2016.

Note 26. Transition to IFRS

The financial statements for fiscal year 2017 are the first annual accounts prepared by OKEA in accordance with IFRS. Financial statements in previous years were prepared in accordance with Norwegian generally accepted accounting policies (NGAAP) for small entities.

The accounting policies described in note 2 have been used to prepare the Company's accounts for 2017, comparable figures for 2016 and an IFRS opening balance sheet as at 1 January 2016, which is the Company's date of transition from NGAAP to IFRS.

This note explains the adjustments made in relation to NGAAP so that the balance sheets at 1 January 2016 and 31 December 2016 and the income statement for 2016 can be presented in accordance with IFRS.

Reconciliation effects resulting from transition to IFRS as per 31 December 2016

		NGAAP	Adjustments	IFRS
Amounts in NOK `000	Note	**31.12.2016**		**31.12.2016**
ASSETS				
Non-current assets				
Deferred tax assets	1	36 980	50	37 031
Goodwill	1	-	8 057	8 057
Exploration and evaluation assets		4 752		4 752
Oil and gas properties	1	525 487	-12 564	512 923
Furniture, fixtures and office equipment		224		224
Total non-current assets		**567 444**	**-4 457**	**562 987**
Current assets				
Trade and other receivables		105 561		105 561
Restricted cash		-	-	-
Cash and cash equivalents		37 889	-	37 889
Total current assets		**143 450**	**-**	**143 450**
TOTAL ASSETS		**710 894**	**-4 457**	**706 437**
EQUITY AND LIABILITIES				
Equity				
Share capital		11 337		11 337
Share premium		216 125		216 125
Unregistered share capital		146 968		146 968
Accumulated loss	1	-5 496	-4 457	-9 953
Total equity		**368 933**	**-4 457**	**364 477**
Non-current liabilities				
Provisions		202 466		202 466
Total non-current liabilities		**202 466**	**-**	**202 466**
Current liabilities				
Trade and other payables		25 899		25 899
Intercompany loan		20 237		20 237
Public dues payable		17 285		17 285
Provisions, current		76 074		76 074
Total current liabilities		**139 494**	**-**	**139 494**
Total liabilities		**341 960**	**-**	**341 960**
TOTAL EQUITY AND LIABILITIES		**710 894**	**-4 457**	**706 437**

Reconciliation of equity:	
Equity according to NGAAP 31.12.2016	368 933
Effect of acquisition of licences	-4 457
Equity according to IFRS 31.12.2016	364 477

Note 26. Transition to IFRS (continued)

Reconciliation effects resulting from transition to IFRS for the 2016 income statement

		NGAAP	Adjustments	IFRS
Amounts in NOK `000	Note	2016		2016
Revenues from crude oil and gas sales	2	494	-494	-
Other operating income	2	-	494	494
Total operating income		**494**	**-**	**494**
Production expenses		-148		-148
Exploration expenses		-547		-547
Depreciation, depletion and amortization		-178		-178
Employee benefits expenses		-13 772		-13 772
Other operating expenses		-14 281		-14 281
Total operating expenses		**-28 926**	**-**	**-28 926**
Profit / loss (-) from operating activities		**-28 432**	**-**	**-28 432**
Finance income		2 460		2 460
Finance costs		-5 334		-5 334
Net financial items		**-2 874**	**-**	**-2 874**
Profit / loss (-) before income tax		**-31 307**	**-**	**-31 307**
Income taxes	1	30 105	-4 457	25 648
Net profit / loss (-) for the period		**-1 202**	**-4 457**	**-5 659**

Notes:

1. The acquisition of interest in Ivar Aasen in 2016 was treated as an asset acquisition under NGAAP. Under IFRS the acquisition is treated as a business combination, with recognition of deferred tax and goodwill. See note 25 for further information.

2. Reclassification of revenue; under IFRS the sales amount of the lifted and delivered volumes are presented as revenues from crude oil and gas sales, while the change in over/under lift is presented as other operating income.

Note 26. Transition to IFRS (continued)

Reconciliation effects resulting from transition to IFRS as per 1 January 2016

The transition from NGAAP to IFRS did not result in any transition differences as per 1 January 2016.

		NGAAP	Adjustments	IFRS
Amounts in NOK `000	Note	**31.12.2015**		**01.01.2016**
ASSETS				
Non-current assets				
Deferred tax assets		10 616		10 616
Goodwill		-		-
Exploration and evaluation assets		-		-
Oil and gas properties		-		-
Furniture, fixtures and office equipment		30		30
Total non-current assets		**10 646**	**-**	**10 646**
Current assets				
Trade and other receivables		1 995		1 995
Restricted cash		-	-	-
Cash and cash equivalents		8 744	-	8 744
Total current assets		**10 738**	**-**	**10 738**
TOTAL ASSETS		**21 384**	**-**	**21 384**
EQUITY AND LIABILITIES				
Equity				
Share capital		1 100		1 100
Share premium		20 900		20 900
Unregistered share capital		-		-
Accumulated loss		-4 294		-4 294
Total equity		**17 706**	**-**	**17 706**
Non-current liabilities				
Provisions		-		-
Total non-current liabilities		**-**	**-**	**-**
Current liabilities				
Trade and other payables		2 392		2 392
Intercompany loan		-		-
Public dues payable		1 287		1 287
Provisions, current		-		-
Total current liabilities		**3 679**	**-**	**3 679**
Total liabilities		**3 679**	**-**	**3 679**
TOTAL EQUITY AND LIABILITIES		**21 384**	**-**	**21 384**

Reconciliation of equity:	
Equity according to NGAAP 01.01.2016	17 706
Equity according to IFRS 01.01.2016	17 706

Note 27. Reserves (unaudited)

Proved and probable reserves	**Mill barrels oil equivalents (mmboe)**	
	2017	**2016**
Balance at 1 January	7,5	-
Acquisition of reserves	3,3	7,5
Reclassification and other changes	-0,0	-
Production	-0,1	-0,0
Total reserves at 31 December	**10,6**	**7,5**

Expected reserves represent the Company's share of reserves according to the SPE/ WPC/ AAPG/ SPEE Petroleum Resources Management system (SPE - PRMS) published in 2007 and with Oslo Stock Exchange's requirements for the disclosure of hydrocarbon reserves and contingent resources; circular 9/ 2009. The figures represent best estimate of proved and probable reserve estimates (mean).

Note 28. Events after the balance sheet date

In 2018 OKEA has restructured the Company's equity, by way of transforming the preference shares into ordinary shares. The restructuring included a reduction of the Company's share capital, by repayment of the par value of the preference shares with NOK 23 299 700, from NOK 24 738 100 to NOK 1 438 400. Subsequent to the share capital reduction, a related increase of the Company's share capital with NOK 1 686 600, from NOK 1 438 400 to NOK 3 125 000, where the amount paid out of the Company in the share capital reduction (by way of establishing a receivable on the Company) was used as contribution on the new shares that were issued. The net effect of this restructuring of the Company's equity was a transforming of the preference shares into ordinary shares.

OKEA has in 2018 issued 590 144 new shares at a price of NOK 179 paid in cash, adding MNOK 105.6 in total new equity.

The Company has in 2018 issued 125 000 warrants to existing minority shareholders as of 31st December 2017.

In 2018 OKEA has entered into an agreement for divesting 15% of the license Grevling to Chrysaor.

The plan for development and operation of Yme New Development was approved by Norwegian authorities in 2018.

To the General Meeting of OKEA AS

Independent Auditor's Report

Report on the Audit of the Financial Statements

Opinion

We have audited the financial statements of OKEA AS which comprise the balance sheet as at 31 December 2017, income statement, statement of comprehensive income, statement of changes in equity and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements are prepared in accordance with law and regulations and present fairly, in all material respects, the financial position of the Company as at 31 December 2017, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as adopted by EU.

Basis for Opinion

We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company as required by laws and regulations, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other information

Management is responsible for the other information. The other information comprises Letter from the Directors 2017, but does not include the financial statements and our auditor's report thereon.

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

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

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

Responsibilities of the Board of Directors and the Managing Director for the Financial Statements

The Board of Directors and the Managing Director (management) are responsible for the preparation in accordance with law and regulations, including fair presentation of the financial statements in accordance with International Financial Reporting Standards as adopted by the EU, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Auditor's Responsibilities for the Audit of the Financial Statements

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

As part of an audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including ISAs, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error. We design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with the Board of Directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Report on Other Legal and Regulatory Requirements

Opinion on Registration and Documentation

Based on our audit of the financial statements as described above, and control procedures we have considered necessary in accordance with the International Standard on Assurance Engagements *(ISAE) 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information*, it is our opinion that management has fulfilled its duty to produce a proper and clearly set out registration and documentation of the Company's accounting information in accordance with the law and bookkeeping standards and practices generally accepted in Norway.

Stavanger, 5 April 2018
PricewaterhouseCoopers AS

Gunnar Slettebø
State Authorised Public Accountant

OKEA AS

Statement of Comprehensive Income

Amounts in NOK `000	Q1 2018 (unaudited)	Q1 2017 (unaudited)	Year 2017 (audited)
Revenues from crude oil and gas sales	2 314	872	38 429
Other operating income	14 022	7 225	5 007
Total operating income	**16 336**	**8 096**	**43 435**
Production expenses	-2 390	-1 632	-7 654
Exploration expenses	-11 211	-3 498	-28 710
Depreciation, depletion and amortization	-5 883	-3 738	-18 025
Employee benefits expenses	-11 033	-6 674	-11 707
Other operating expenses	-4 317	-6 083	-33 128
Total operating expenses	**-34 833**	**-21 624**	**-99 223**
Profit / loss (-) from operating activities	**-18 498**	**-13 527**	**-55 788**
Finance income	29 101	157	2 392
Finance costs	-23 905	-1 417	-27 098
Net financial items	**5 197**	**-1 260**	**-24 706**
Profit / loss (-) before income tax	**-13 301**	**-14 788**	**-80 494**
Income taxes	12 815	12 078	68 780
Net profit / loss (-)	**-486**	**-2 709**	**-11 714**
Other comprehensive income:			
Total other comprehensive income	**-**	**-**	**-**
Total comprehensive income / loss (-)	**-486**	**-2 709**	**-11 714**

OKEA AS

Balance Sheet at 31 December

Amounts in NOK `000	31.03.2018 (unaudited)	31.03.2017 (unaudited)	31.12.2017 (audited)
ASSETS			
Non-current assets			
Deferred tax assets	89 456	45 012	85 091
Goodwill	8 057	8 057	8 057
Exploration and evaluation assets	5 752	4 752	5 752
Oil and gas properties	716 864	567 674	676 378
Furniture, fixtures and office equipment	216	222	217
Other financial non-current assets	8 875	4 097	-
Total non-current assets	**829 219**	**629 815**	**775 495**
Current assets			
Trade and other receivables	132 084	109 217	120 207
Restricted cash	859 633	-	907 799
Cash and cash equivalents	121 230	17 418	29 609
Total current assets	**1 112 946**	**126 634**	**1 057 615**
TOTAL ASSETS	**1 942 165**	**756 449**	**1 833 110**
EQUITY AND LIABILITIES			
Equity			
Share capital	3 715	18 685	24 738
Share premium	595 991	355 745	470 755
Other paid in capital	157	-	-
Accumulated loss	-22 153	-12 662	-21 667
Total equity	**577 711**	**361 767**	**473 827**
Non-current liabilities			
Provisions	321 168	203 966	319 668
Interest-bearing loans and borrowings	918 091	-	963 312
Total non-current liabilities	**1 239 259**	**203 966**	**1 282 979**
Current liabilities			
Trade and other payables	116 145	47 044	66 013
Intercompany loan	1 141	73 545	1 141
Public dues payable	2 374	2 146	3 596
Provisions, current	5 535	67 981	5 554
Total current liabilities	**125 195**	**190 716**	**76 304**
Total liabilities	**1 364 454**	**394 682**	**1 359 283**
TOTAL EQUITY AND LIABILITIES	**1 942 165**	**756 449**	**1 833 110**

Statement of Changes in Equity

Amounts in NOK `000	Share capital	Share premium	Other paid in capital	Unregistered share capital	Accumulated loss	Total equity
Equity at 1 January 2017	11 337	216 125	-	146 968	-9 953	364 477
Net profit / loss (-) for the year					-11 714	-11 714
Registration of share issues in Company Registry	7 348	139 620		-146 968		
Share issues, cash	3 275	62 225				65 500
Share issues, conversion of debt	2 778	52 786				55 564
Equity at 31 December 2017	**24 738**	**470 755**	**-**	**-**	**-21 667**	**473 827**
Equity at 1 January 2018	24 738	470 755	-	-	-21 667	473 827
Net profit / loss (-) for the year					-486	-486
Effect of equity restructuring	-21 613	21 613				0
Share issues	590	103 622				104 212
Share based payment			157			157
Equity at 31 March 2018	**3 715**	**595 991**	**157**	**-**	**-22 153**	**577 711**

Statement of Cash Flows

Amounts in NOK `000	Q1 2018 (unaudited)	Q1 2017 (unaudited)	Year 2017 (audited)
Cash flow from operating activities			
Profit / loss (-) before income tax	-13 301	-14 788	-80 494
Income tax paid/received	-	-	3 740
Depreciation, depletion and amortization	5 883	3 738	18 025
Accretion ARO	1 500	1 500	6 001
Change in trade and other receivables	-11 876	-3 656	-6 420
Change in trade and other payables	49 049	6 007	17 485
Change in other non-current items	-45 221	-	4 385
Net cash flow from / used in (-) operating activities	**-13 966**	**-7 199**	**-37 278**
Cash flow from investing activities			
Investement in exploration and evaluation assets	-	-	-999
Investment in oil and gas properties	-46 366	-66 580	-123 099
Investment in furniture, fixtures and office machines	-	-	-
Investment in (-)/release of restricted cash	48 166	-	-907 799
Net cash flow from / used in (-) investing activities	**1 800**	**-66 580**	**-1 031 897**
Cash flow from financing activities			
Proceeds from intercompany borrowings	-	53 308	92 280
Repayment of intercompany borrowings	-	-	-58 300
Net proceeds from borrowings, bond loan	-	-	961 415
Net proceeds from share issues	103 787	-	65 500
Net cash flow from / used in (-) financing activities	**103 787**	**53 308**	**1 060 895**
Net increase/ decrease (-) in cash and cash equivalents	**91 621**	**-20 471**	**-8 280**
Cash and cash equivalents at the beginning of the period	29 609	37 889	37 889
Cash and cash equivalents at the end of the period	**121 230**	**17 418**	**29 609**
Restricted cash at the end of the period	859 633	-	907 799
Restricted and unrestricted cash at the end of the period	**980 862**	**17 418**	**937 408**

Notes to the interim financial statements first quarter 2018

Note 1 - General and corporate information

These financial statements are the unaudited interim condensed financial statements of OKEA AS for the first quarter of 2018. OKEA AS is a private limited liability company incorporated and domiciled in Norway, with its main office located in Trondheim.

Note 2 - Basis of preparation

The interim accounts have been prepared in accordance with IAS 34 Interim Financial Reporting. The interim accounts do not include all the information required in the annual accounts and should therefore be read in conjunction with the annual accounts for 2017. The annual accounts for 2017 were prepared in accordance with the EU`s approved IFRS.

Note 3 - Accounting policies

The accounting policies adopted in the preparation of the interim accounts are consistent with those followed in the preparation of the annual accounts for 2017. In addition the Company has adopted the IFRS 9 Financial Instruments and IFRS 15 Revenue from Contracts with Customers effective from 1 January 2018. The implementaion of these standards did not have any effect on the financial statements.

Note 4 - Critical accounting estimates and judgements

The preparation of the interim accounts entails the use of judgements, estimates and assumptions that affect the application of accounting policies and the amounts recognised as assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and other factors that are considered to be reasonable under the circumstances. The actual results may deviate from these estimates. The material assessments underlying the application of the company's accounting policies and the main sources of uncertainty are the same for the interim accounts as for the annual accounts for 2017.

Note 5 - Business segments

The Company’s only business segment is development and production of oil and gas on the Norwegian Continental Shelf.

Note 6 Taxes

Income taxes recognised in the income statement

Amounts in NOK `000	**Q1 2018**	**Q1 2017**	**Year 2017**
Change in deferred taxes	3 940	7 982	48 061
Tax refund current year	8 875	4 097	20 719
Total income taxes recognised in the income statement	**12 815**	**12 078**	**68 780**

Reconciliation of income taxes

Amounts in NOK `000	Q1 2018	Q1 2017	Year 2017
Profit / loss (-) before income taxes	**-13 301**	**-14 788**	**-80 494**
Expected income tax at nominal tax rate, 25% (2017: 24%)	3 192	3 549	19 319
Expected petroleum tax, 55% (2017: 54%)	7 183	7 985	43 467
Permanent differences	-215	-36	-208
Effect of uplift	2 740	451	10 181
Financial items	-85	129	-8 766
Effect of new tax rates	-	-	337
Adjustments previous year and other	-	-	4 450
Total income taxes recognised in the income statement	**12 815**	**12 078**	**68 780**
Effective income tax rate	**96 %**	**82 %**	**85 %**

Specification of tax effects on temporary differences, tax losses and uplift carried forward

Amounts in NOK `000	31.03.2018	31.03.2017	31.12.2017
Tangible and intangible non-current assets	-345 543	-241 618	-335 377
Provisions	247 028	212 119	245 873
Interest-bearing loans and borrowings	-20 462	-	-5 069
Current items	-12 124	-	-2 526
Tax losses carried forward, offshore 23%	68 516	18 821	51 824
Tax losses carried forward, offshore 55%	119 455	40 180	100 520
Uplift carried forward, offshore 55%	32 587	15 512	29 847
Total deferred tax assets / liabilities (-) recognised	**89 456**	**45 012**	**85 091**

Deferred tax is calculated based on tax rates applicable on the balance sheet date. Ordinary income tax is 23%, to which is added a special tax for oil and gas companies at the rate of 55%, giving a total tax rate of 78%.

Companies operating on the Norwegian Continental Shelf under the offshore tax regime can claim the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid in cash (including interest) from the tax authorities when operations cease. Deferred tax assets that are based on offshore tax losses carried forward are therefore normally recognised in full.

There is no time limit on the right to carry tax losses forward in Norway.

Note 7 Tangible assets

Amounts in NOK `000	Oil and gas properties in production	Oil and gas properties under development	Furniture, fixtures and office machines	Total
Cost at 1 January 2018	141 524	553 044	233	694 800
Additions	646	45 720	-	46 366
Cost at 31 March 2018	**142 170**	**598 764**	**233**	**741 167**
Accumulated depreciation and impairment at 1 January 2018	-18 189	-	-15	-18 205
Depreciation year to date	-5 881	-	-2	-5 883
Accumulated depreciation and impairment at 31 March 2018	**-24 070**	**-**	**-17**	**-24 087**
Carrying amount at 31 March 2018	**118 100**	**598 764**	**216**	**717 079**

Note 8 Share capital

Number of shares	Ordinary shares	Preference shares	Total shares
Outstanding shares at 1.1.2018	1 438 400	23 299 700	24 738 100
Capital decrease, redemption of preference shares		-23 299 700	-23 299 700
New shares issued during 2018	2 276 744	-	2 276 744
Number of outstanding shares at 31 March	**3 715 144**	**-**	**3 715 144**

Nominal value NOK per share at 31 March 2018	1
Share capital NOK at 31 March 2018	3 715 144

Note 9 Provisions

Amounts in NOK `000	Total non-current
Provision at 1 January 2018	319 668
Additions and adjustments	-
Changes in Operator's estimate	-
Unwinding of discount	1 500
Total provisions at 31 March 2018	**321 168**

Asset retirement obligations

Provisions for asset retirement obligations represent the future expected costs for close-down and removal of oil equipment and production facilities. The provision is based on the Operator's best estimate. The net present value of the estimated obligation is calculated using a discount rate. The assumptions are based on the economic environment around the balance sheet date. Actual asset retirement costs will ultimately depend upon future market prices for the necessary works which will reflect market conditions at the relevant time. Furthermore, the timing of the close-down is likely to depend on when the field ceases to produce at economically viable rates. This in turn will depend upon future oil and gas prices, which are inherently uncertain.

Note 10 Changes in Intererest-bearing loans and borrowings

Amounts in NOK `000	
Interest bearing loans and borrowings 1 January 2018	963 312
Non-cash changes:	
Amortization of transaction costs, bond loan	1 718
Foreign exchange movement, bond loan	-46 938
Interest bearing loans and borrowings 31 March 2018	**918 091**

Note 11 - Events after the balance sheet date

No material events have occurred after the balance sheet date.